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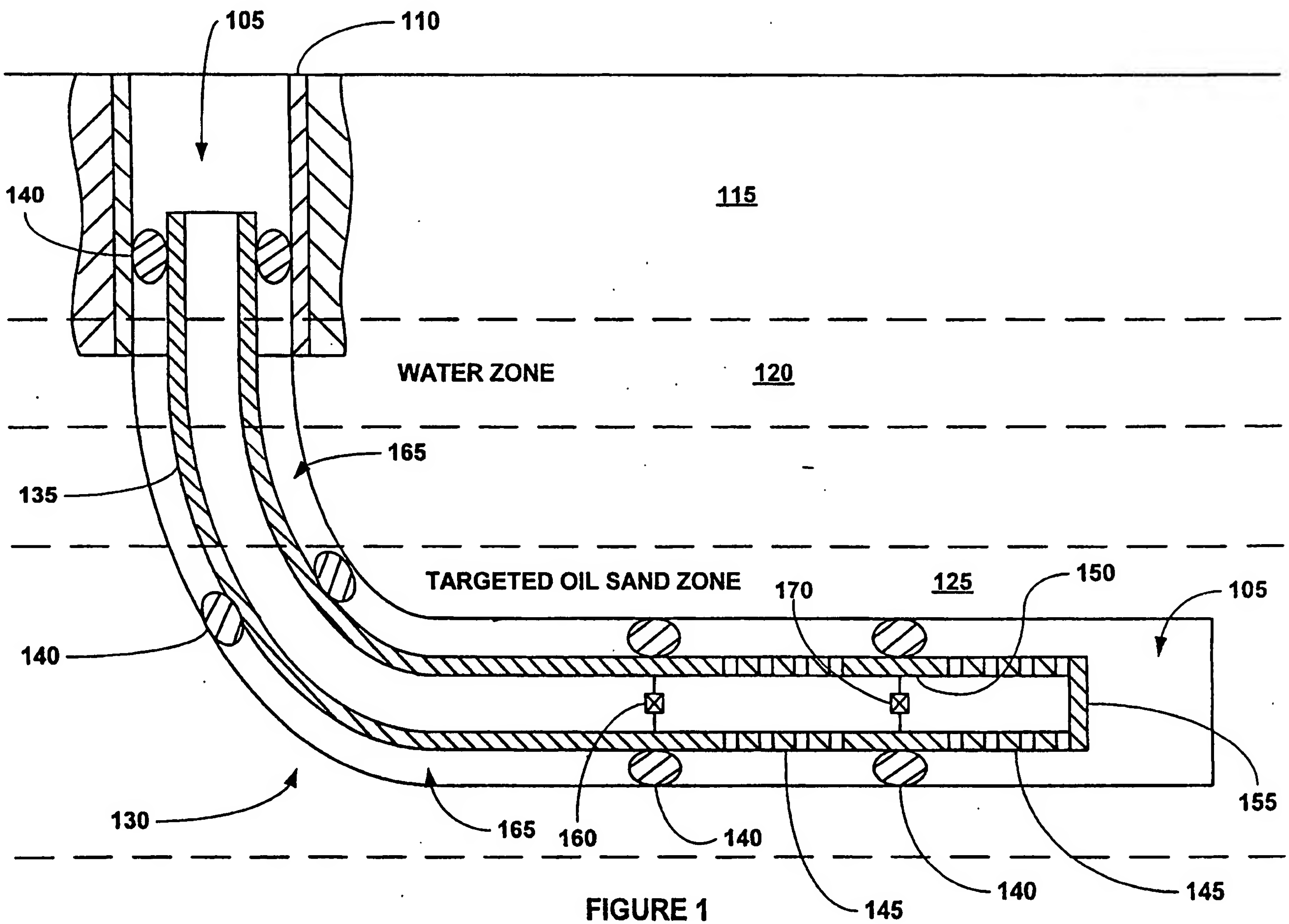
(72) Inventor(s):
Robert Lance Cook
Lev Ring
Kevin Waddell
David Paul Brisco

(73) Proprietor(s):
Shell Internationale Research Maatschappij B.V.
(Incorporated in the Netherlands)
Department IP/43 Carel Van Bylandtlaan 30, 2596 HR The Hague, Netherlands

(74) Agent and/or Address for Service:
Haseltine Lake & Co
Redcliff Quay, 120 Redcliff Street,
BRISTOL, BS1 6HU, United Kingdom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WATER ZONE
120
165
135
TARGETED OIL SAND ZONE
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165
160
140
155
145
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145

FIGURE 1

2/19

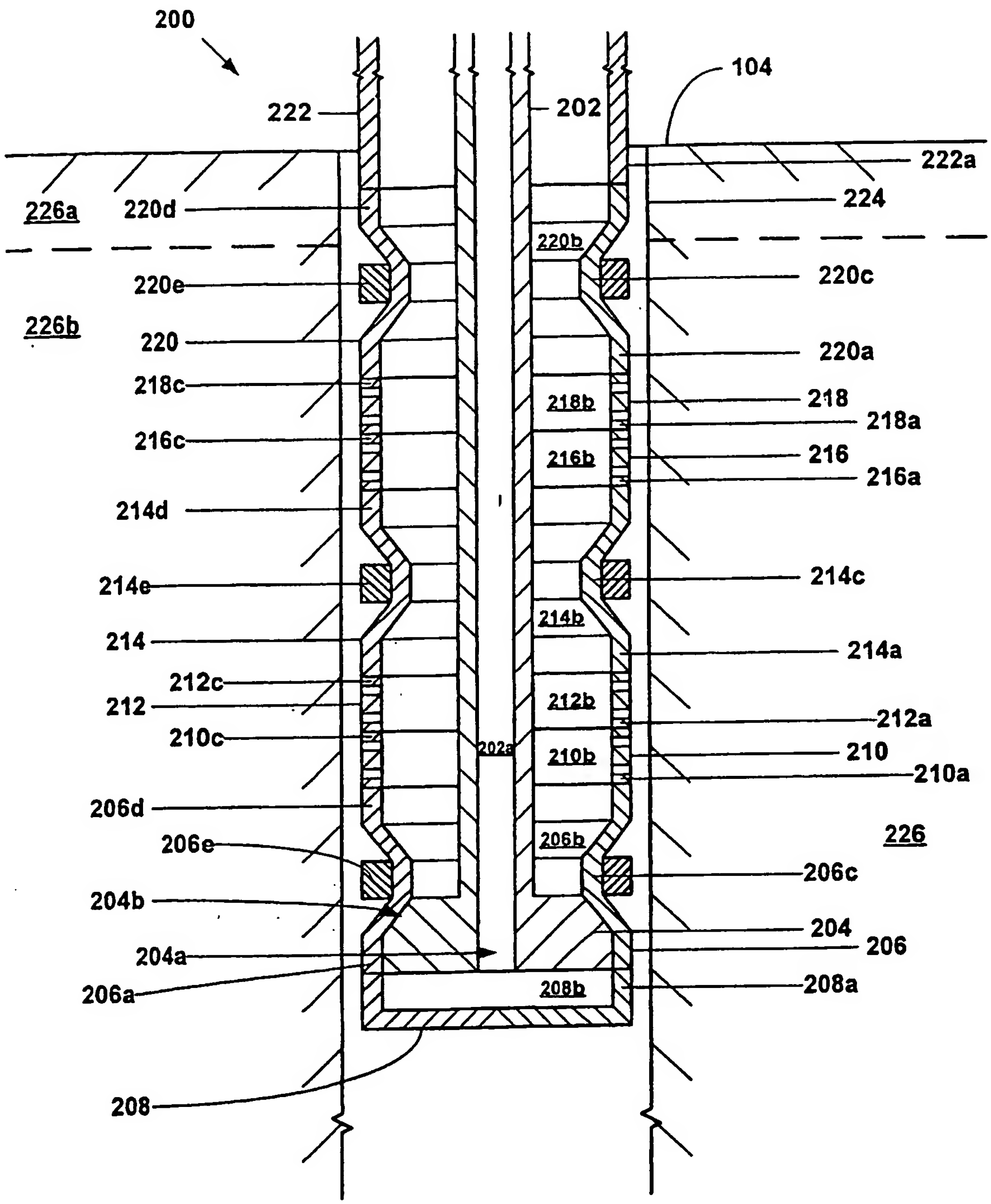
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Fig. 2a

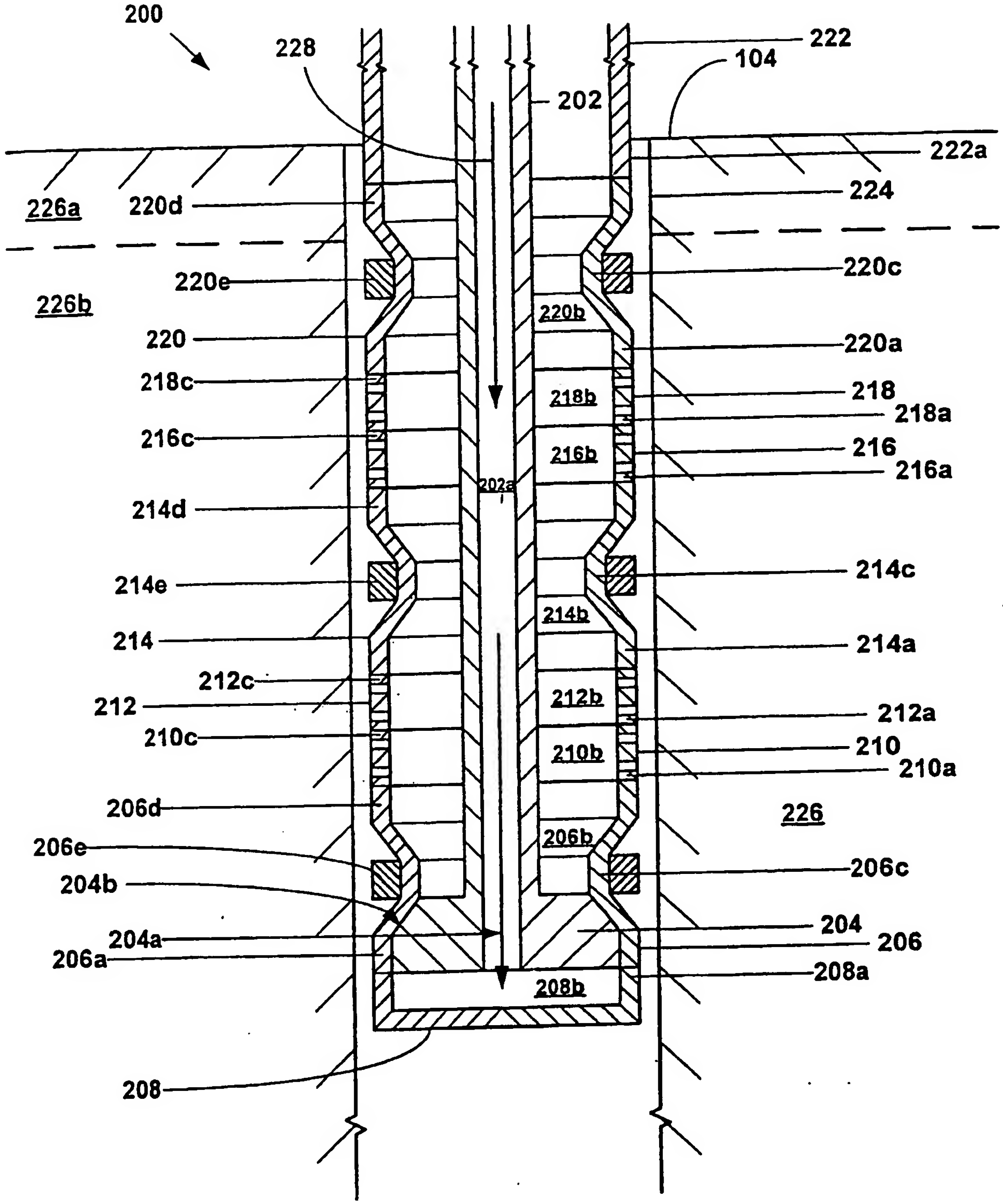
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Fig. 2b

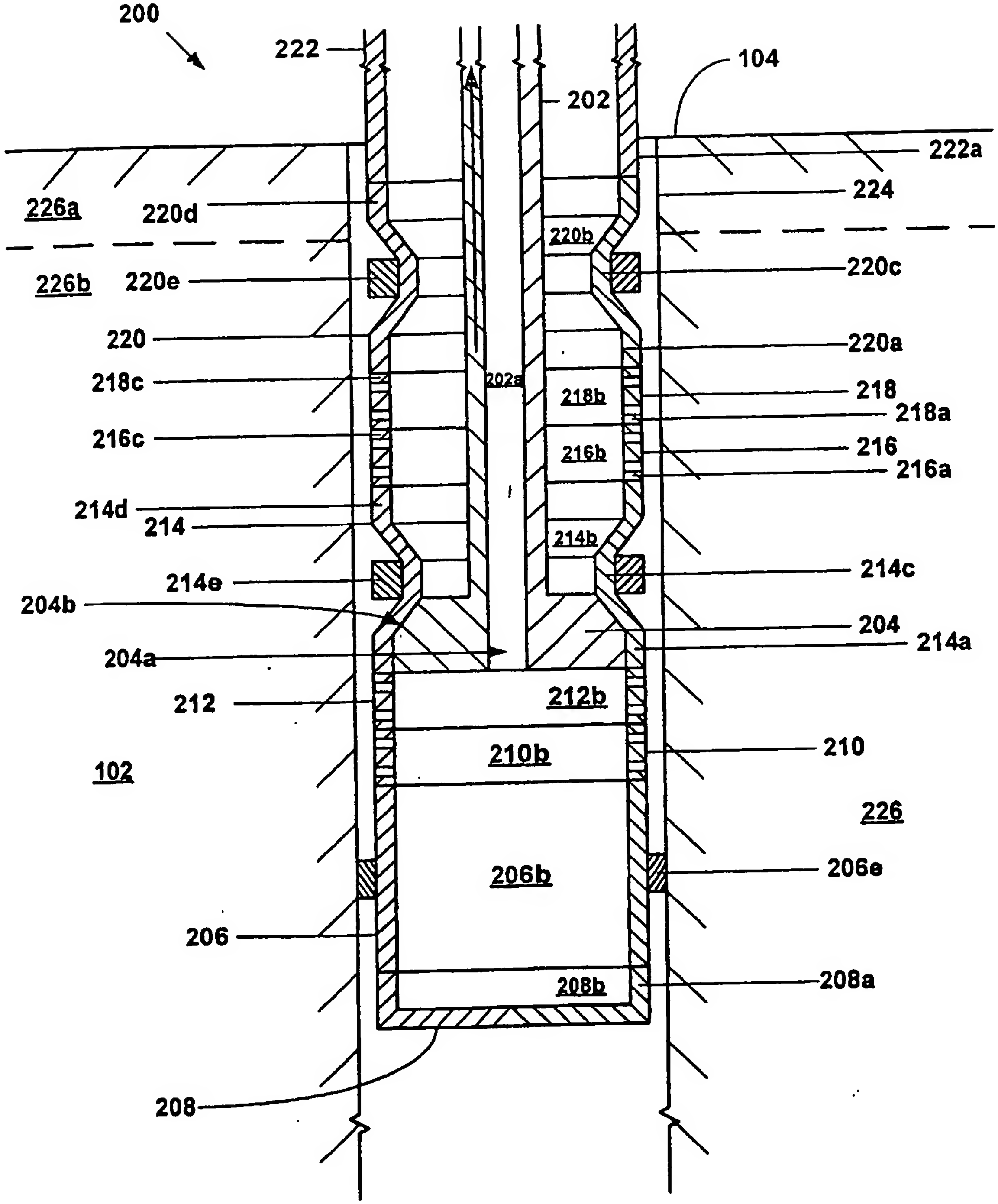
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Fig. 2c

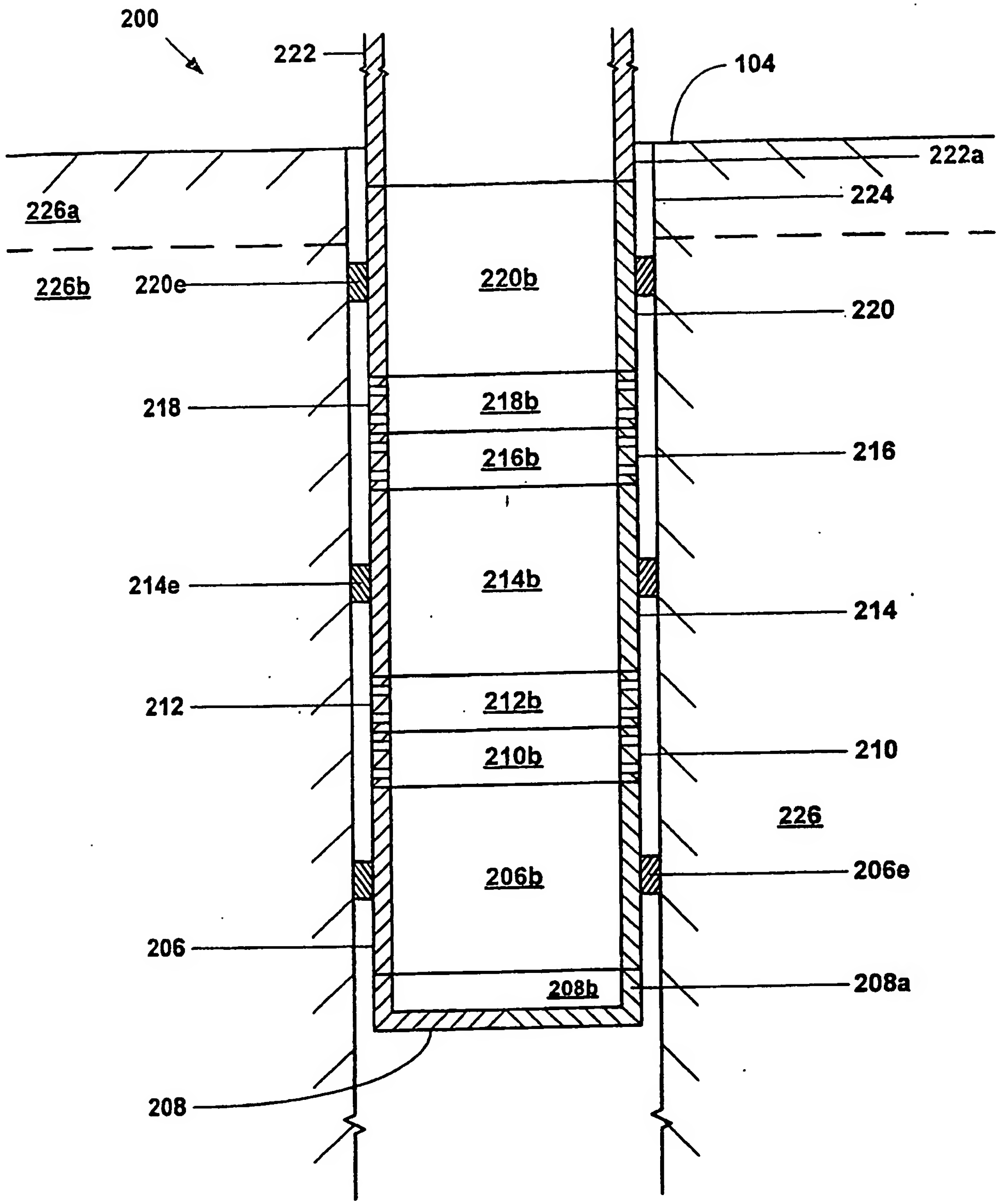
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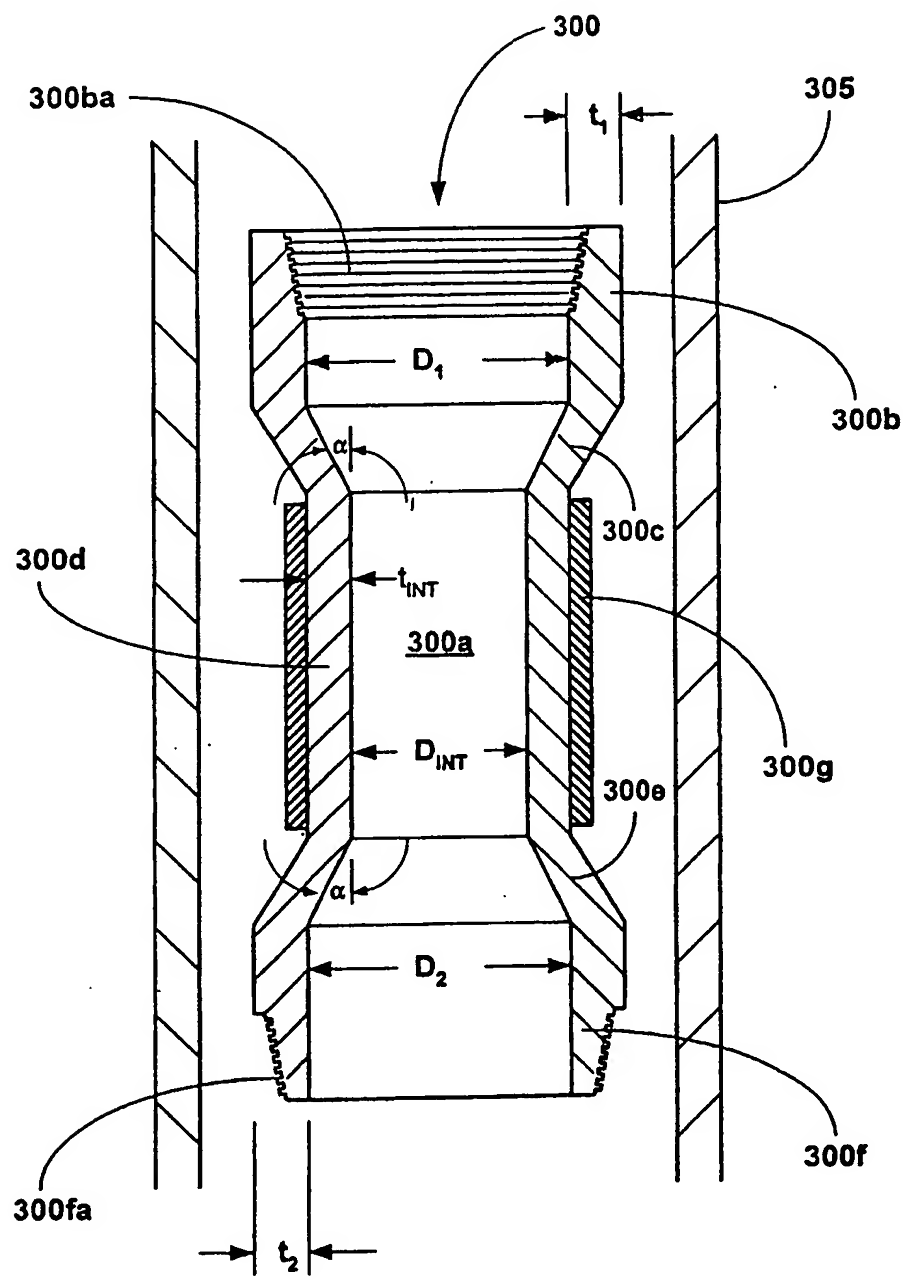
Fig. 2d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300b
α
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300fa
t_2

Fig. 3

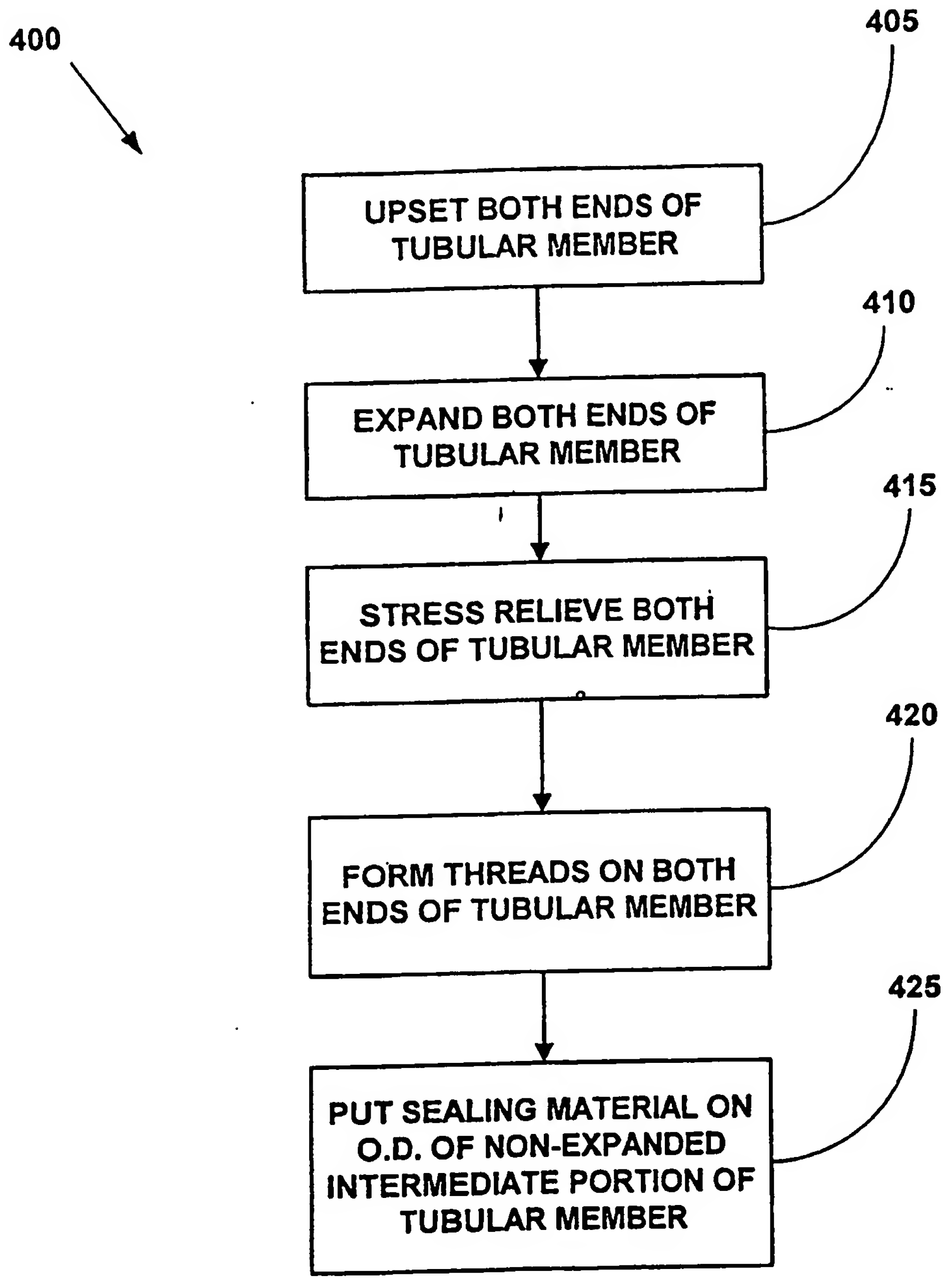
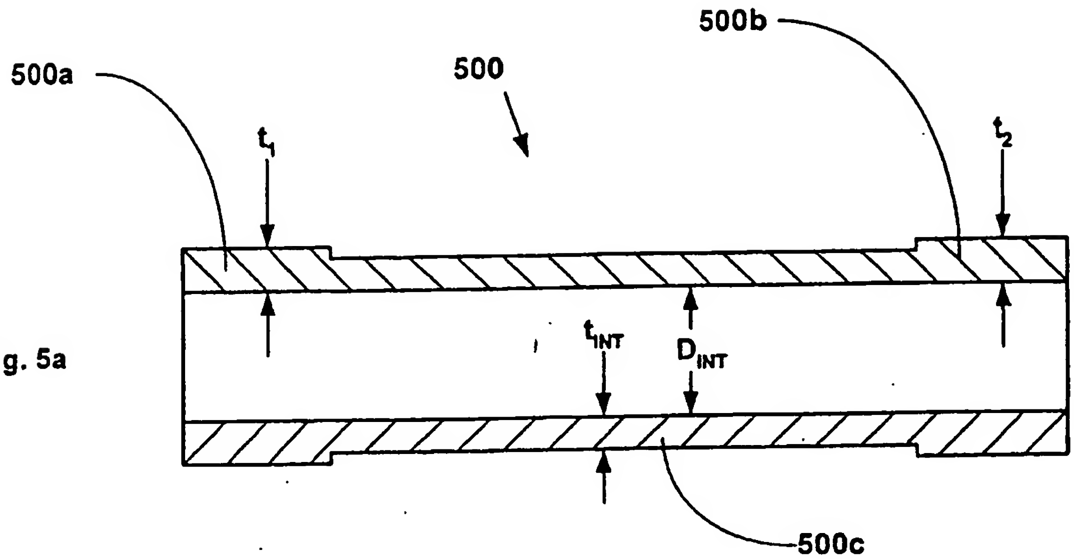

400
405
UPSET BOTH ENDS OF TUBULAR MEMBER
410
EXPAND BOTH ENDS OF TUBULAR MEMBER
415
STRESS RELIEVE BOTH ENDS OF TUBULAR MEMBER
420
FORM THREADS ON BOTH ENDS OF TUBULAR MEMBER
425
PUT SEALING MATERIAL ON O.D. OF NON-EXPANDED INTERMEDIATE PORTION OF TUBULAR MEMBER

Fig. 4

Fig. 5a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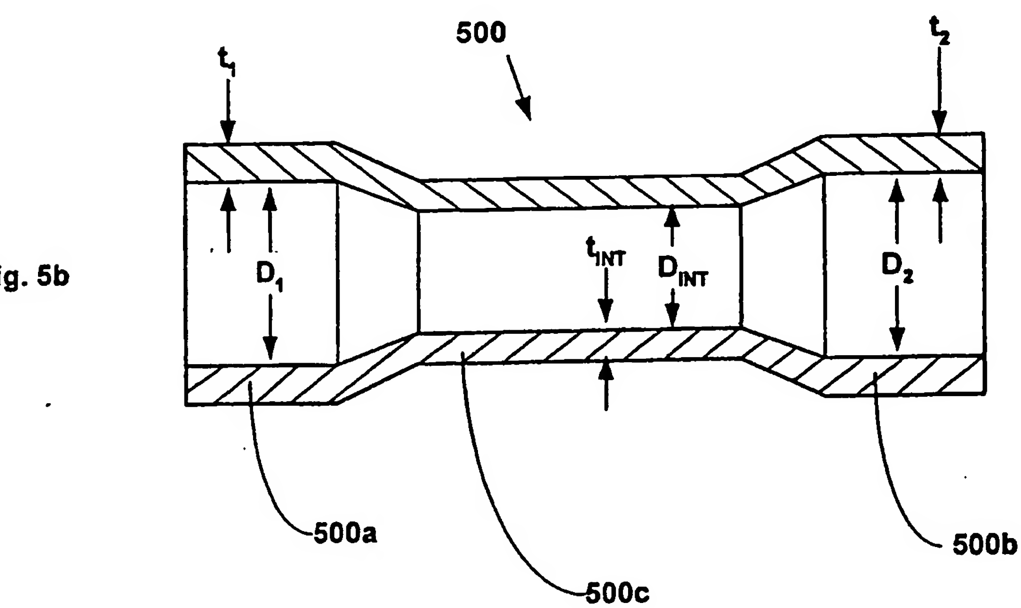
t_2
t_{INT}
D_{INT}
500c

Fig. 5b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D_{INT}
D_2
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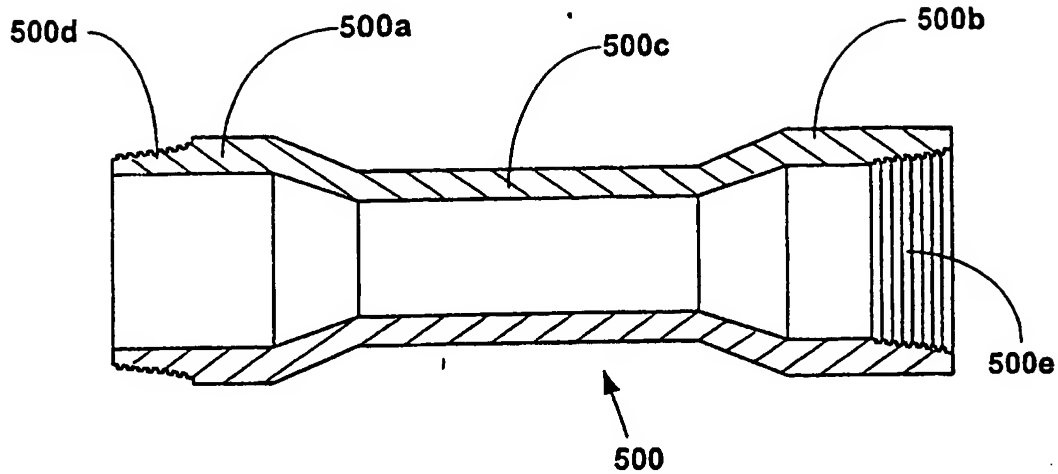
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Fig. 5c

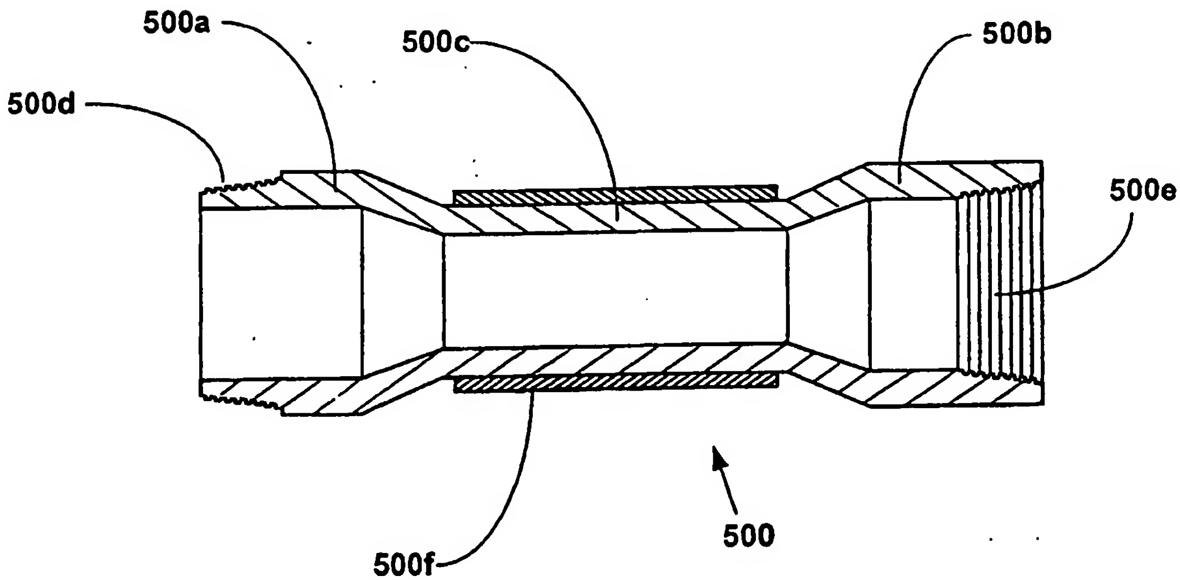
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Fig. 5d

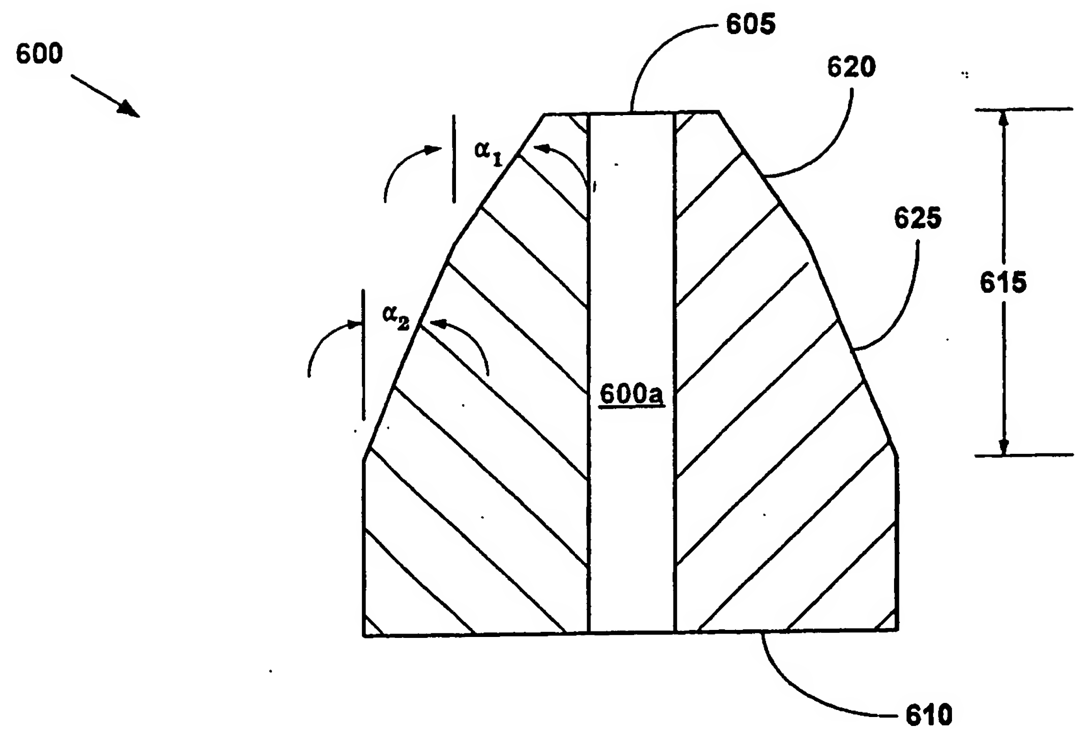


Fig. 6

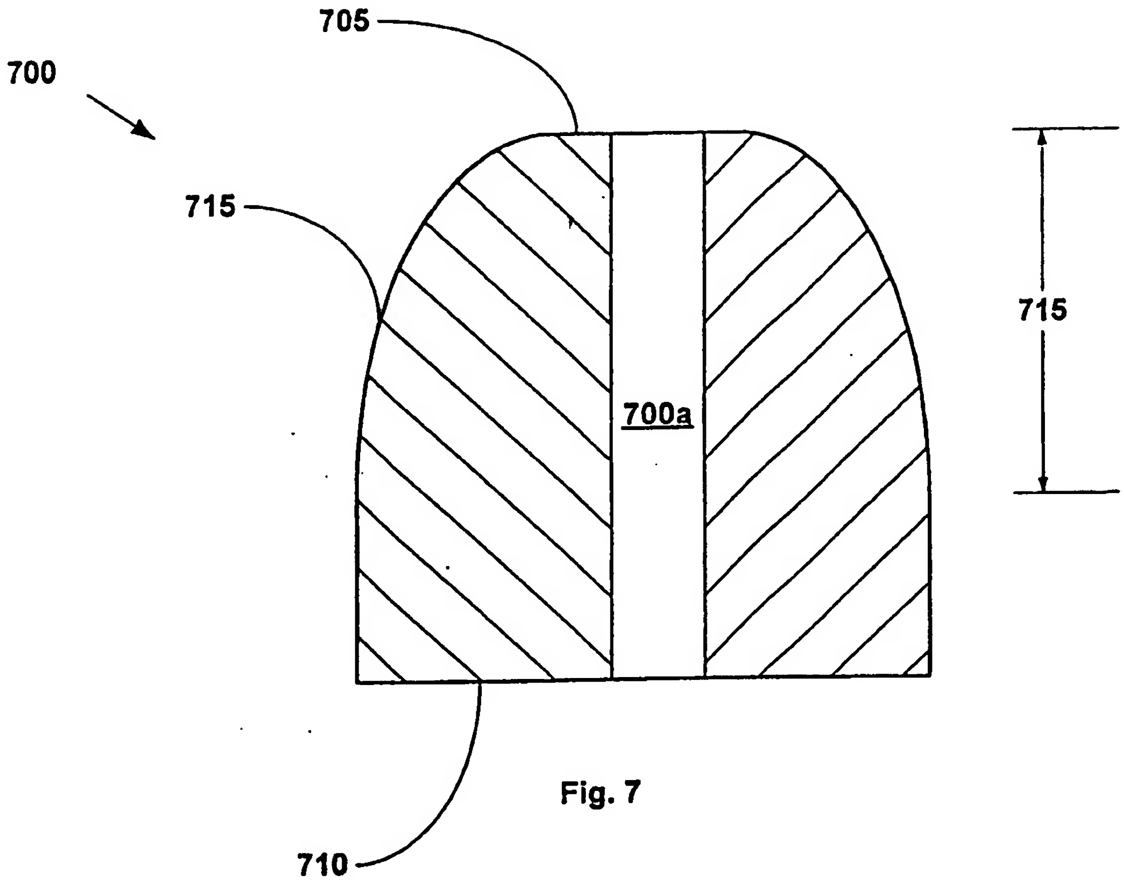
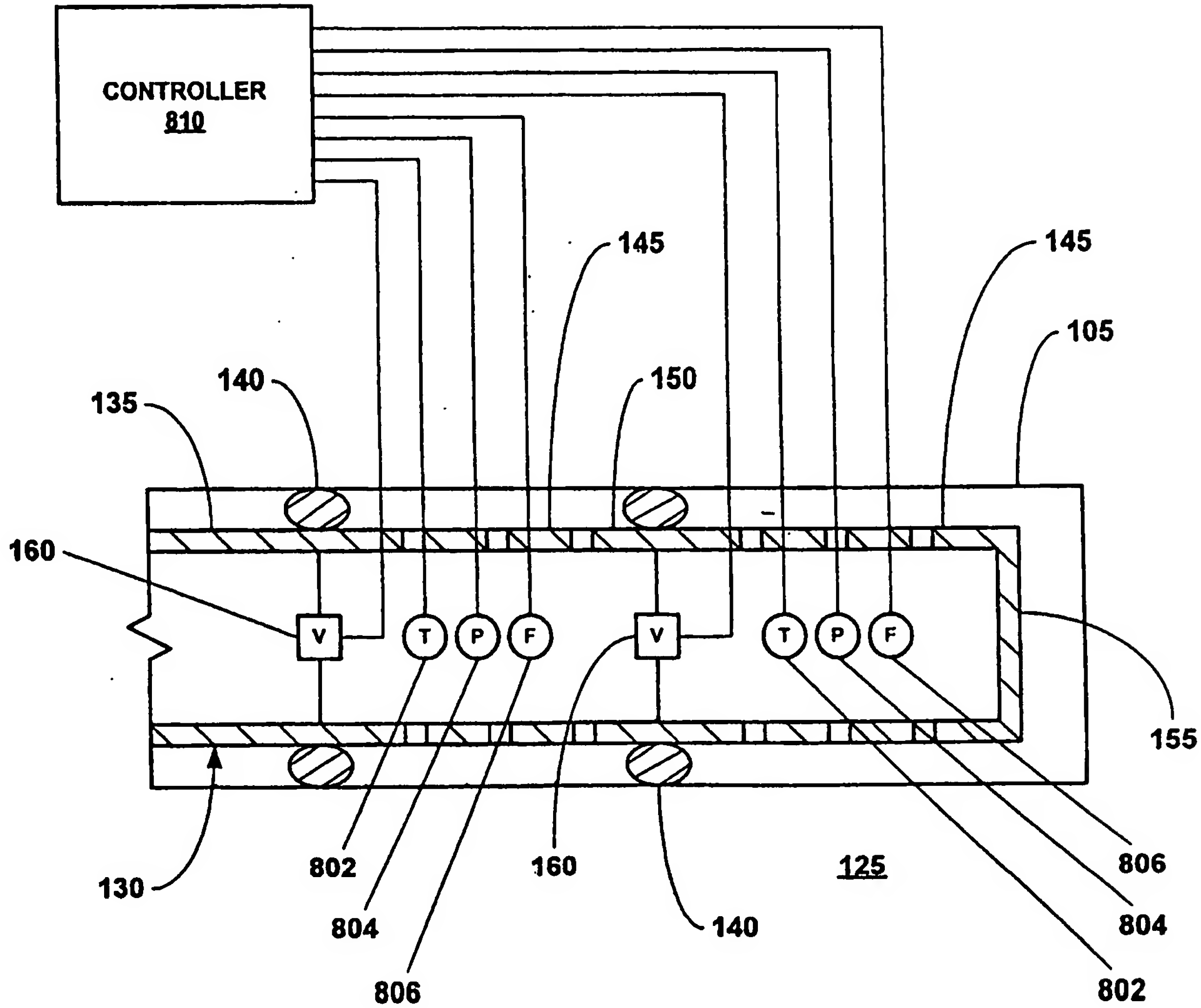


Fig. 7



CONTROLLER
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FIGURE 8

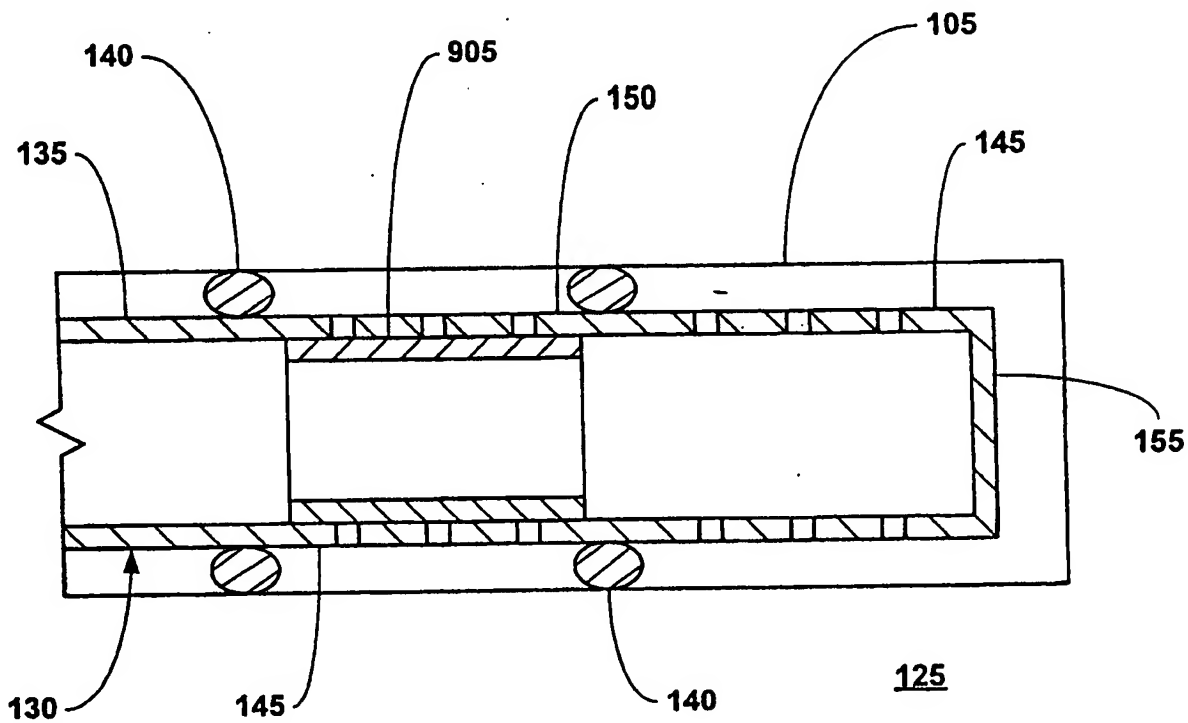

FIGURE 9

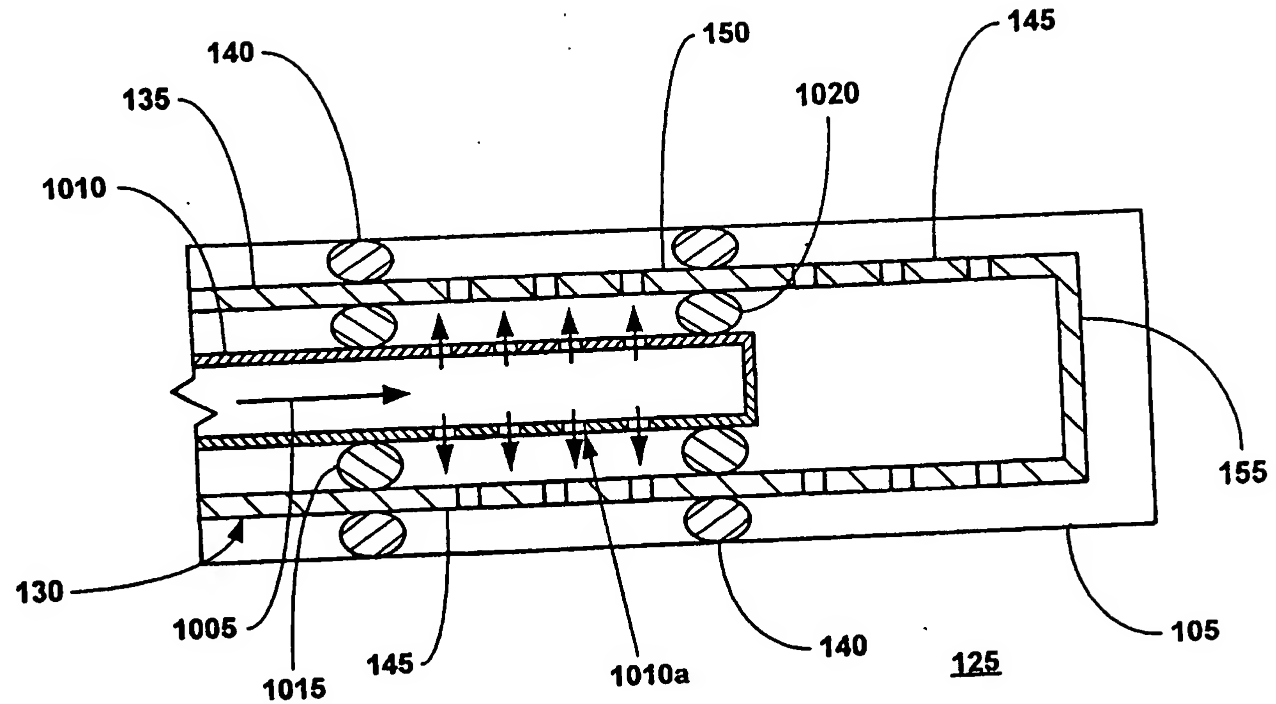
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FIGURE 10

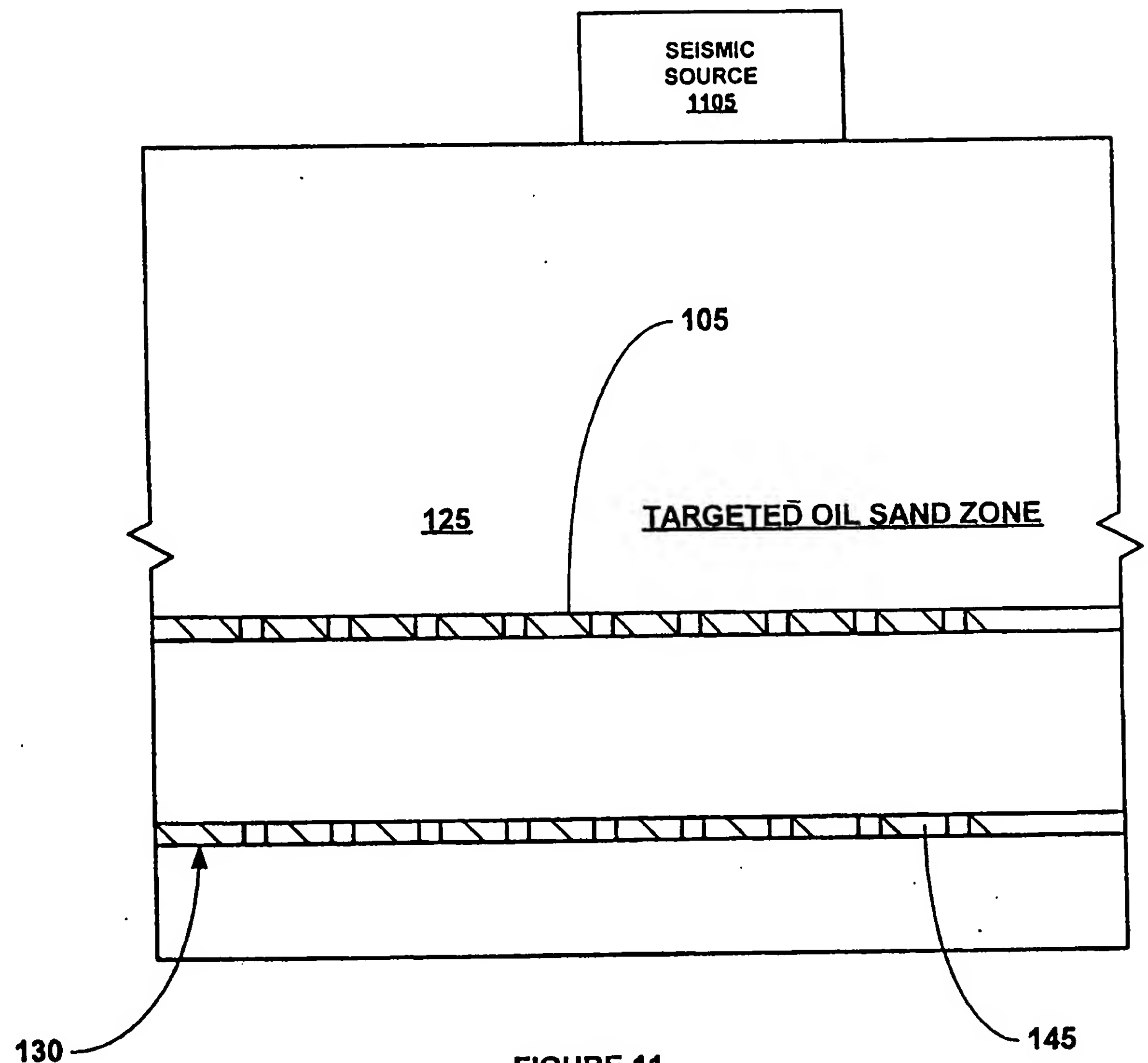
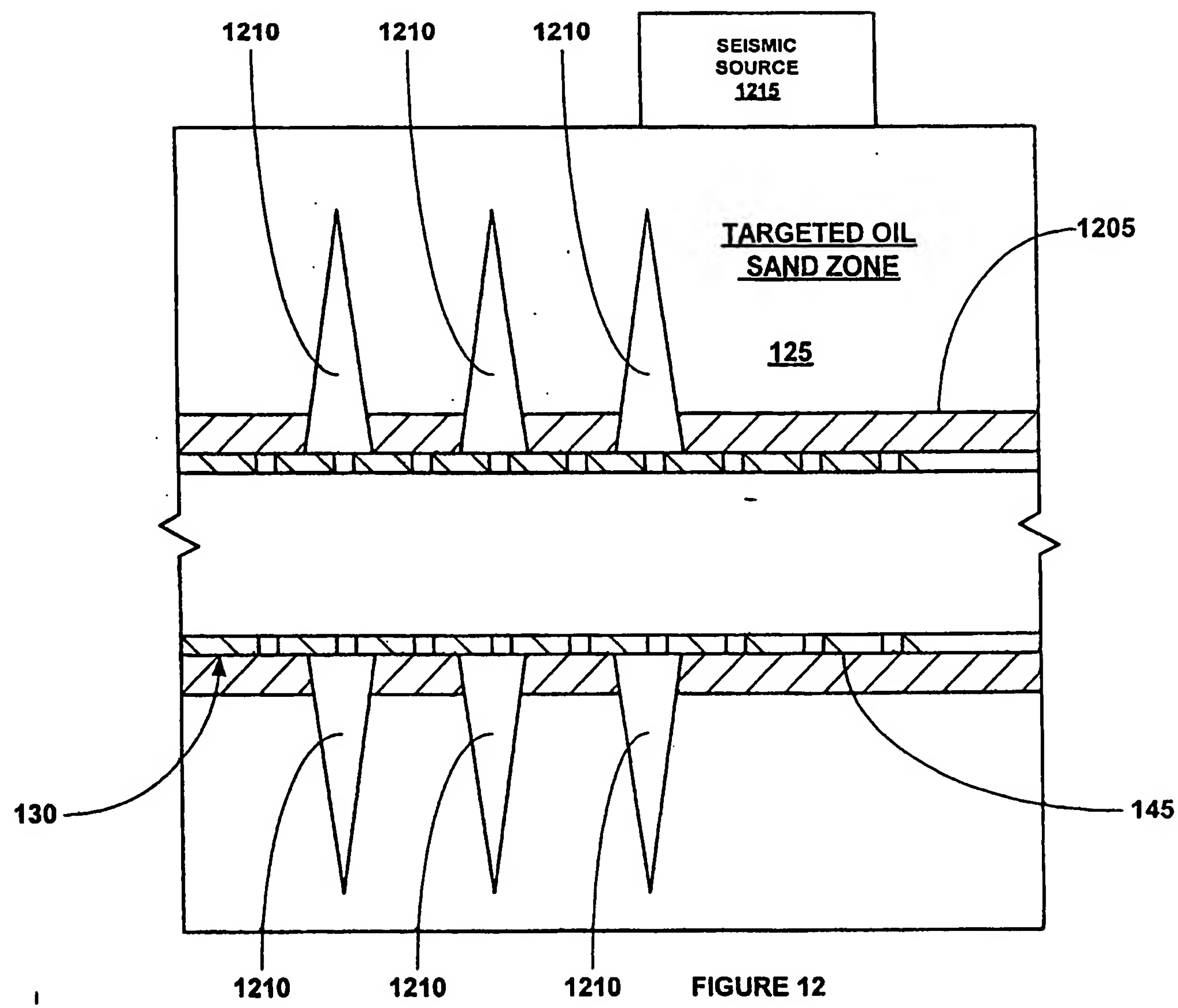


FIGURE 11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1205
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1210
1210
1210

FIGURE 12

17/19

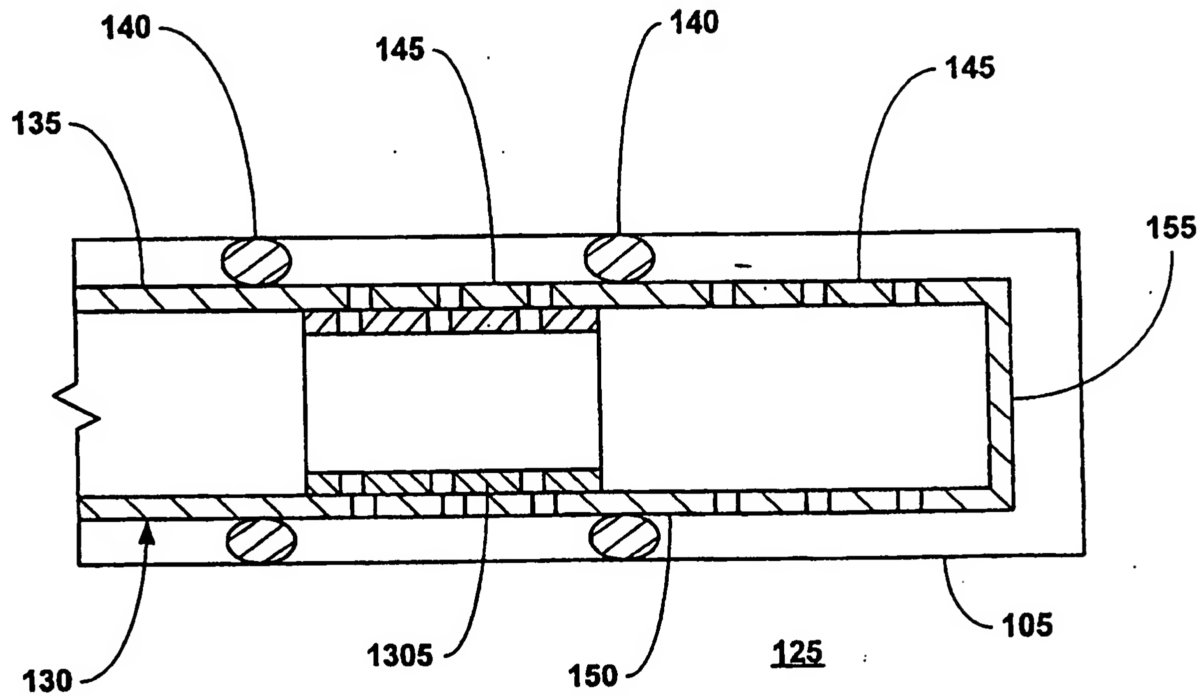


FIGURE 13

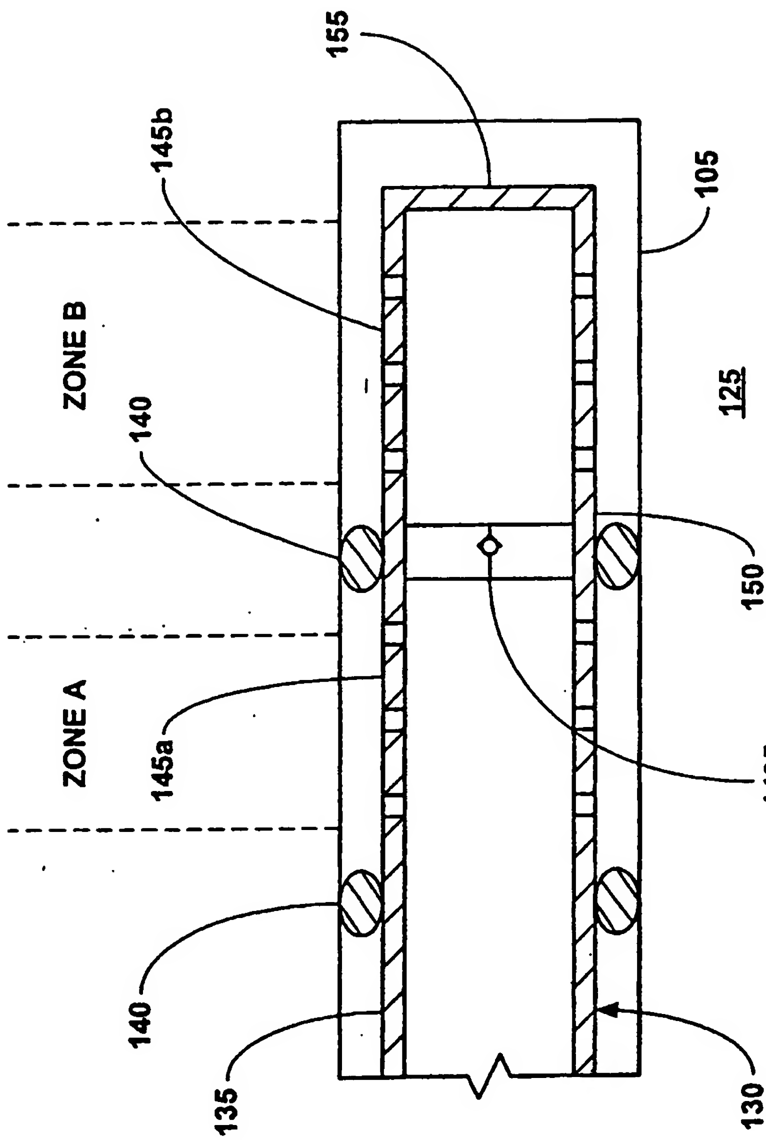
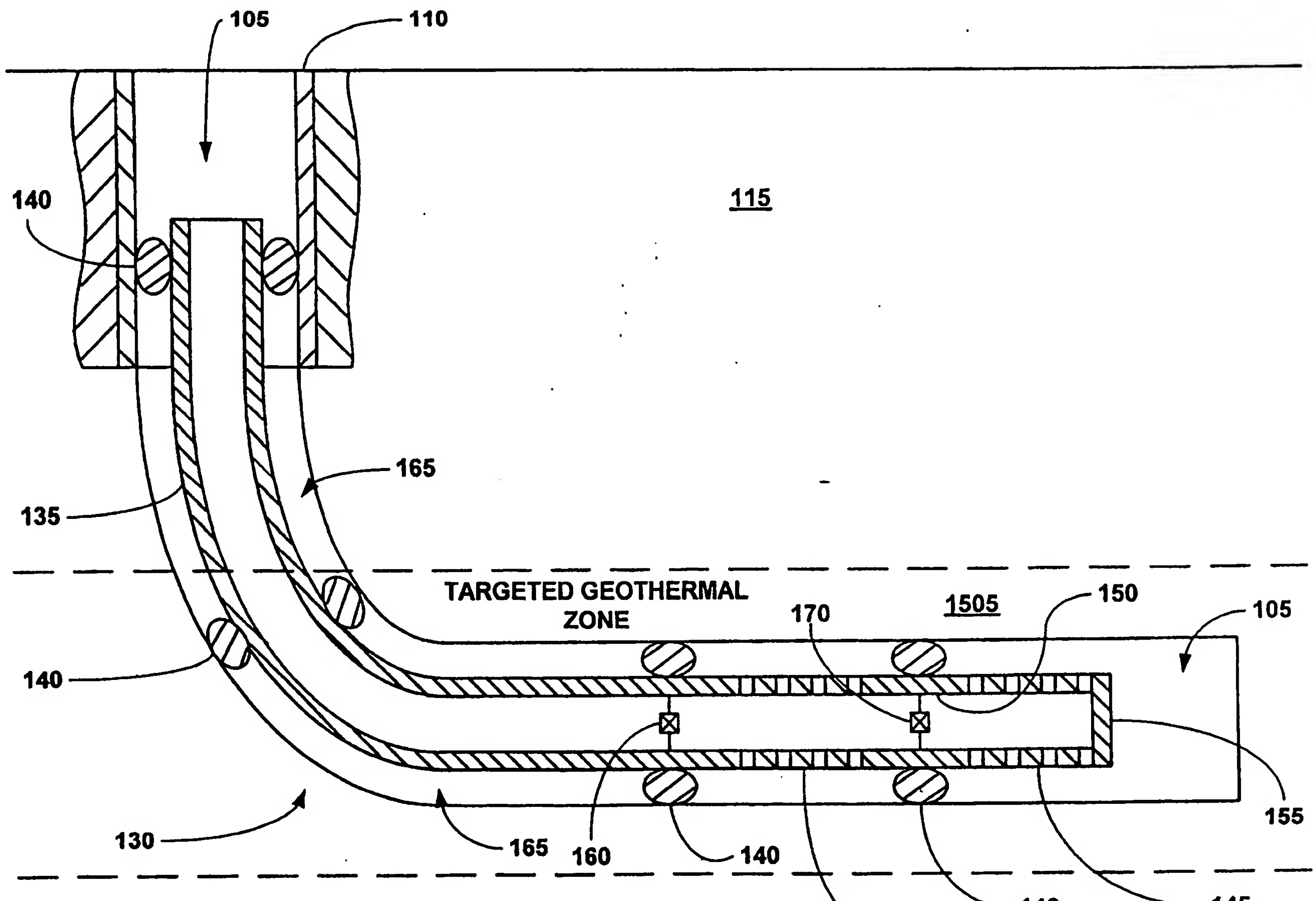


FIGURE 14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110
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135
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TARGETED GEOTHERMAL ZONE
170
1505
150
105
140
130
165
160
140
155
145
140
145

FIGURE 15

ISOLATION OF SUBTERRANEAN ZONES

Background of the Invention

This invention relates generally to oil and gas exploration, and in particular to isolating certain subterranean zones to facilitate oil and gas exploration.

During oil exploration, a wellbore typically traverses a number of zones within a subterranean formation. Some of these subterranean zones will produce oil and gas, while others will not. Further, it is often necessary to isolate subterranean zones from one another in order to facilitate the exploration for and production of oil and gas. Existing methods for isolating subterranean production zones in order to facilitate the exploration for and production of oil and gas are complex and expensive.

The present invention is directed to overcoming one or more of the limitations of the existing processes for isolating subterranean zones during oil and gas exploration.

Summary of the Invention

According to the present invention, there is provided an apparatus, comprising:

a zonal isolation assembly positioned within a wellbore comprising:

one or more solid tubular members, each solid tubular member including one or more external seals;

one or more perforated tubular members each including a longitudinal and one or more radial passages coupled to the solid tubular members;

one or more flow control valves operably coupled to the perforated tubular members for controlling the flow of fluidic materials through the perforated tubular members;

one or more temperature sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating temperature within the perforated tubular members;

one or more pressure sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating pressure within the perforated tubular members;

one or more flow sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating flow rate within the perforated tubular members;

a controller operably coupled to the flow control valves, the temperature sensors, the pressure sensors, and the flow sensors for monitoring the temperature, pressure and flow sensors and controlling the operation of the flow control valves; and

one or more solid tubular liners coupled to the interior surfaces of one or more of the perforated tubular members for sealing at least some of the radial passages of the perforated tubular members; and

a shoe coupled to the zonal isolation assembly;

wherein at least one of the solid tubular members and the perforated tubular members are formed by a radial expansion process performed within the wellbore; and

wherein the solid tubular liners are formed by a radial expansion process performed within the wellbore.

According to another aspect of the present invention, there is provided a method of isolating a first subterranean zone from a second subterranean zone in a wellbore, comprising:

positioning one or more solid tubulars within the wellbore, the solid tubulars traversing the first subterranean zone;

positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the second subterranean zone;

radially expanding at least one of the solid tubulars and perforated tubulars within the wellbore;

fluidicly coupling the perforated tubulars and the solid tubulars;

preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid tubulars and perforated tubulars;

monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

According to another aspect of the present invention, there is provided a method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, comprising;

positioning one or more solid tubulars within the wellbore;

positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the producing subterranean zone;

radially expanding at least one of the solid tubulars and the perforated tubulars within the wellbore;

fluidicly coupling the solid tubulars with the casing;

fluidicly coupling the perforated tubulars with the solid tubulars;

fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore;

fluidicly coupling at least one of the perforated tubulars with the producing subterranean zone;

monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

According to another aspect of the present invention, there is provided a system for isolating a first subterranean zone from a second subterranean zone in a wellbore, comprising:

means for positioning one or more solid tubulars within the wellbore, the solid tubulars traversing the first subterranean zone;

means for positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the second subterranean zone;

means for radially expanding at least one of the solid tubulars and perforated tubulars within the wellbore;

means for fluidicly coupling the perforated tubulars and the solid tubulars;

means for preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid tubulars and perforated tubulars;

means for monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

means for controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

means for positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

means for radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

According to another aspect of the present invention, there is provided a system for extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, comprising;

means for positioning one or more solid tubulars within the wellbore;

means for positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the producing subterranean zone;

means for radially expanding at least one of the solid tubulars and the perforated tubulars within the wellbore;

means for fluidicly coupling the solid tubulars with the casing;

means for fluidicly coupling the perforated tubulars with the solid tubulars;

means for fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore;

means for fluidicly coupling at least one of the perforated tubulars with the producing subterranean zone;

means for monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

means for controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

means for positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

means for radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the isolation of subterranean zones.

Fig. 2a is a cross sectional illustration of the placement of a system for isolating subterranean zones within a borehole.

Fig. 2b is a cross sectional illustration of the system of Fig. 2a during the injection of a fluidic material into the tubular support member.

Fig. 2c is a cross sectional illustration of the system of Fig. 2b while pulling the tubular expansion cone out of the wellbore.

Fig. 2d is a cross sectional illustration of the system of Fig. 2c after the tubular expansion cone has been completely pulled out of the wellbore.

Fig. 3 is a cross sectional illustration of the expandable tubular members of the system of Fig. 2a.

Fig. 4 is a flow chart illustration of a method for manufacturing the expandable tubular member of Fig. 3.

Fig. 5a is a cross sectional illustration of the upsetting of the ends of a tubular member.

Fig. 5b is a cross sectional illustration of the expandable tubular member of Fig. 5a after radially expanding and plastically deforming the ends of the expandable tubular member.

Fig. 5c is a cross sectional illustration of the expandable tubular member of Fig. 5b after forming threaded connections on the ends of the expandable tubular member.

Fig. 5d is a cross sectional illustration of the expandable tubular member of Fig. 5c after coupling sealing members to the exterior surface of the intermediate unexpended portion of the expandable tubular member.

Fig. 6 is a cross-sectional illustration of a tubular expansion cone.

Fig. 7 is a cross-sectional illustration of a tubular expansion cone.

Fig. 8 is a fragmentary cross sectional illustration of an alternative system for isolating subterranean zones of Fig. 1.

Fig. 9 is a fragmentary cross sectional illustration of a method for lining one of the perforated tubular members of the system for isolating subterranean zones of Fig. 1 with a solid tubular liner.

Fig. 10 is a fragmentary cross sectional illustration of a method for sealing one of the perforated tubular members of the system for isolating subterranean zones of Fig. 1 with a hardenable fluidic sealing material.

Fig. 11 is a fragmentary cross sectional illustration of a method for coupling one of the perforated tubular members of the system for isolating subterranean zones of Fig. 1 with the surrounding subterranean formation.

Fig. 12 is a fragmentary cross sectional illustration of a method for coupling one of the perforated tubular members of the system for isolating subterranean zones of Fig. 1 with a surrounding perforated wellbore casing.

Fig. 13 is a fragmentary cross sectional illustration of a method for lining one of the perforated tubular members of the system for isolating subterranean zones of Fig. 1 with another perforated tubular member.

Fig. 14 is a fragmentary cross sectional illustration of an alternative system for isolating subterranean zones of Fig. 1 that includes a one-way valve for preventing flow from a producing zone into a depleted zone.

Fig. 15 is a fragmentary cross sectional illustration of an alternative system for isolating subterranean zones of Fig. 1 in which the system is used to extract geothermal energy from a subterranean geothermal zone.

Detailed Description

An apparatus and method for isolating one or more subterranean zones from one or more other subterranean zones is provided. The apparatus and method permits a producing zone to be isolated from a nonproducing zone using a combination of solid and slotted tubulars. In the production mode, the teachings of the present disclosure may be used in combination with conventional, well known, production completion equipment and methods using a series of packers, solid tubing, perforated tubing, and sliding sleeves, which will be inserted into the disclosed apparatus to permit the commingling and/or isolation of the subterranean zones from each other.

Referring to Fig. 1, a wellbore 105 including a casing 110 are positioned in a subterranean formation 115. The subterranean formation 115 includes a number of productive and non-productive zones, including a water zone 120 and a targeted oil sand zone 125. During exploration of the subterranean formation 115, the wellbore

105 may be extended in a well known manner to traverse the various productive and non-productive zones, including the water zone 120 and the targeted oil sand zone 125.

In order to fluidicly isolate the water zone 120 from the targeted oil sand zone 125, an apparatus 130 is provided that includes one or more sections of solid casing 135, one or more external seals 140, one or more sections of perforated casing 145, one or more intermediate sections of solid casing 150, and a solid shoe 155. The perforated casing 145 includes one or more radial passages.

The solid casing 135 provides a fluid conduit that transmits fluids and other materials from one end of the solid casing 135 to the other end of the solid casing 135. The solid casing 135 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. The solid casing 135 comprises oilfield tubulars available from various foreign and domestic steel mills.

The solid casing 135 is preferably coupled to the casing 110. The solid casing 135 may be coupled to the casing 110 using any number of conventional commercially available processes such as, for example, welding, slotted and expandable connectors, or expandable solid connectors. The solid casing 135 is coupled to the casing 110 by using expandable solid connectors. The solid casing 135 may comprise a plurality of such solid casing 135.

The solid casing 135 is preferably coupled to one more of the perforated casings 145. The solid casing 135 may be coupled to the perforated casing 145 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. The solid casing 135 is coupled to the perforated casing 145 by expandable solid connectors.

The solid casing 135 includes one more valve members 160 for controlling the flow of fluids and other materials within the interior region of the casing 135. During the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The casing 135 is placed into the wellbore 105 by expanding the casing 135 in the radial direction into intimate contact with the interior walls of the wellbore 105. The

casing 135 may be expanded in the radial direction using any number of conventional commercially available methods.

The seals 140 prevent the passage of fluids and other materials within the annular region 165 between the solid casings 135 and 150 and the wellbore 105. The seals 140 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. The seals 140 comprise Stratalok epoxy material available from Halliburton Energy Services. The perforated casing 145 permits fluids and other materials to pass into and out of the interior of the perforated casing 145 from and to the annular region 165. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The perforated casing 145 may comprise any number of conventional commercially available sections of slotted tubular casing. The perforated casing 145 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. The perforated casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

The perforated casing 145 is preferably coupled to one or more solid casing 135. The perforated casing 145 may be coupled to the solid casing 135 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. The perforated casing 145 is coupled to the solid casing 135 by expandable solid connectors.

The perforated casing 145 is preferably coupled to one or more intermediate solid casings 150. The perforated casing 145 may be coupled to the intermediate solid casing 150 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The perforated casing 145 is coupled to the intermediate solid casing 150 by expandable solid connectors.

The last perforated casing 145 is preferably coupled to the shoe 155. The last perforated casing 145 may be coupled to the shoe 155 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The last perforated casing 145 is coupled to the shoe 155 by an expandable solid connector.

Instead, the shoe 155 may be coupled directly to the last one of the intermediate solid casings 150.

The perforated casings 145 are positioned within the wellbore 105 by expanding the perforated casings 145 in a radial direction into intimate contact with the interior walls of the wellbore 105. The perforated casings 145 may be expanded in a radial direction using any number of conventional commercially available processes.

The intermediate solid casing 150 permits fluids and other materials to pass between adjacent perforated casings 145. The intermediate solid casing 150 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. The intermediate solid casing 150 comprises oilfield tubulars available from foreign and domestic steel mills.

The intermediate solid casing 150 is preferably coupled to one or more sections of the perforated casing 145. The intermediate solid casing 150 may be coupled to the perforated casing 145 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable connectors. The intermediate solid casing 150 is coupled to the perforated casing 145 by expandable solid connectors. The intermediate solid casing 150 may comprise a plurality of such intermediate solid casing 150.

Each intermediate solid casing 150 includes one more valve members 170 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 150. As will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The intermediate casing 150 is placed into the wellbore 105 by expanding the intermediate casing 150 in the radial direction into intimate contact with the interior walls of the wellbore 105. The intermediate casing 150 may be expanded in the radial direction using any number of conventional commercially available methods.

One or more of the intermediate solid casings 150 may be omitted. Preferably, one or more of the perforated casings 145 are provided with one or more seals 140.

The shoe 155 provides a support member for the apparatus 130. In this manner, various production and exploration tools may be supported by the show 150. The shoe 150 may comprise any number of conventional commercially available shoes suitable

for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. The shoe 150 comprises an aluminum shoe available from Halliburton. The shoe 155 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

The apparatus 130 includes a plurality of solid casings 135, a plurality of seals 140, a plurality of perforated casings 145, a plurality of intermediate solid casings 150, and a shoe 155. More generally, the apparatus 130 may comprise one or more solid casings 135, each with one or more valve members 160, n perforated casings 145, n-1 intermediate solid casings 150, each with one or more valve members 170, and a shoe 155.

During operation of the apparatus 130, oil and gas may be controllably produced from the targeted oil sand zone 125 using the perforated casings 145. The oil and gas may then be transported to a surface location using the solid casing 135. The use of intermediate solid casings 150 with valve members 170 permits isolated sections of the zone 125 to be selectively isolated for production. The seals 140 permit the zone 125 to be fluidicly isolated from the zone 120. The seals 140 further permits isolated sections of the zone 125 to be fluidicly isolated from each other. In this manner, the apparatus 130 permits unwanted and/or non-productive subterranean zones to be fluidicly isolated.

As will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The solid casing 135, the perforated casings 145, the intermediate sections of solid casing 150, and/or the solid shoe 155 may be radially expanded and plastically deformed within the wellbore 105 in a conventional manner and/or using one or more of the methods and apparatus disclosed in one or more of the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial

no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on 4/26/2000, (10) PCT patent application serial no. PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no. 25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999, (18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, (22) U.S. provisional patent application serial no. 60/270,007, attorney docket no. 25791.50, filed on 2/20/2001; (23) U.S. provisional patent application serial no. 60/262,434, attorney docket no. 25791.51, filed on 1/17/2001; (24) U.S, provisional patent application serial no. 60/259,486, attorney docket no. 25791.52, filed on 1/3/2001; (25) U.S. provisional patent application serial no. 60/303,740, attorney docket no. 25791.61, filed on 7/6/2001; (26) U.S. provisional patent application serial no. 60/313,453, attorney docket no. 25791.59, filed on 8/20/2001; (27) U.S. provisional patent application serial no. 60/317,985, attorney docket no. 25791.67, filed on 9/6/2001; (28) U.S. provisional patent application serial no. 60/318,386, attorney docket no. 25791.67.02, filed on 9/10/2001; and (29) U.S. utility patent application serial no. 09/969,922, attorney docket no. 25791.69, filed on 10/3/2001. The radial clearances between the radially expanded solid casings 135, perforated casings 145, intermediate sections of solid casing 150, and/or the solid shoe

155 and the wellbore 105 may be eliminated thereby eliminating the annulus between the solid casings, the perforated casings 145, the intermediate sections of solid casing 150, and/or the solid shoe 155 and the wellbore 105. In this manner, the optional need for filling the annulus with a filler material such as, for example, gravel, may be eliminated.

Referring to Figs. 2a-2d, a system 200 for isolating subterranean formations includes a tubular support member 202 that defines a passage 202a. A tubular expansion cone 204 that defines a passage 204a is coupled to an end of the tubular support member 202. The tubular expansion cone 204 includes a tapered outer surface 204b for reasons to be described.

A pre-expanded end 206a of a first expandable tubular member 206 that defines a passage 206b is adapted to mate with and be supported by the tapered outer surface 204b of the tubular expansion cone 204. The first expandable tubular member 206 further includes an unexpanded intermediate portion 206c, another pre-expanded end 206d, and a sealing member 206e coupled to the exterior surface of the unexpended intermediate portion. The inside and outside diameters of the pre-expanded ends, 206a and 206d, of the first expandable tubular member 206 are greater than the inside and outside diameters of the unexpended intermediate portion 206c. An end 208a of a shoe 208 is coupled to the pre-expanded end 206a of the first expandable tubular member 206 by a conventional threaded connection.

An end 210a of a slotted tubular member 210 that defines a passage 210b is coupled to the other pre-expanded end 206d of the first expandable tubular member 206 by a conventional threaded connection. Another end 210c of the slotted tubular member 210 is coupled to an end 212a of a slotted tubular member 212 that defines a passage 212b by a conventional threaded connection. A pre-expanded end 214a of a second expandable tubular member 214 that defines a passage 214b is coupled to the other end 212c of the tubular member 212. The second expandable tubular member 214 further includes an unexpended intermediate portion 214c, another pre-expanded end 214d, and a sealing member 214e coupled to the exterior surface of the unexpended intermediate portion. The inside and outside diameters of the pre-expanded ends, 214a and 214d, of the second expandable tubular member 214 are greater than the inside and outside diameters of the unexpended intermediate portion 214c.

An end 216a of a slotted tubular member 216 that defines a passage 216b is coupled to the other pre-expanded end 214d of the second expandable tubular member 214 by a conventional threaded connection. Another end 216c of the slotted tubular member 216 is coupled to an end 218a of a slotted tubular member 218 that defines a passage 218b by a conventional threaded connection. A pre-expanded end 220a of a third expandable tubular member 220 that defines a passage 220b is coupled to the other end 218c of the slotted tubular member 218. The third expandable tubular member 220 further includes an unexpended intermediate portion 220c, another pre-expanded end 220d, and a sealing member 220e coupled to the exterior surface of the unexpended intermediate portion. The inside and outside diameters of the pre-expanded ends, 220a and 220d, of the third expandable tubular member 220 are greater than the inside and outside diameters of the unexpended intermediate portion 220c.

An end 222a of a tubular member 222 is threadably coupled to the end 30d of the third expandable tubular member 220.

The inside and outside diameters of the pre-expanded ends, 206a, 206d, 214a, 214d, 220a and 220d, of the expandable tubular members, 206, 214, and 220, and the slotted tubular members 210, 212, 216, and 218, may be substantially equal. The sealing members, 206e, 214e, and 220e, of the expandable tubular members, 206, 214, and 220, respectively, further include anchoring elements for engaging the wellbore casing 104. The slotted tubular members, 210, 212, 216, and 218, may be conventional slotted tubular members having threaded end connections suitable for use in an oil or gas well, an underground pipeline, or as a structural support. The slotted tubular members, 210, 212, 216, and 218 may be conventional slotted tubular members for recovering or introducing fluidic materials such as, for example, oil, gas and/or water from or into a subterranean formation.

As illustrated in Fig. 2a, the system 200 is initially positioned in a borehole 224 formed in a subterranean formation 226 that includes a water zone 226a and a targeted oil sand zone 226b. The borehole 224 may be positioned in any orientation from vertical to horizontal. The upper end of the tubular support member 202 may be supported in a conventional manner using, for example, a slip joint, or equivalent device in order to permit upward movement of the tubular support member and tubular expansion cone 204 relative to one or more of the expandable tubular members, 206, 214, and 220, and tubular members, 210, 212, 216, and 218.

As illustrated in Fig. 2b, a fluidic material 228 is then injected into the system 200, through the passages, 202a and 204a, of the tubular support member 202 and tubular expansion cone 204, respectively.

As illustrated in Fig. 2c, the continued injection of the fluidic material 228 through the passages, 202a and 204a, of the tubular support member 202 and the tubular expansion cone 204, respectively, pressurizes the passage 18b of the shoe 18 below the tubular expansion cone thereby radially expanding and plastically deforming the expandable tubular member 206 off of the tapered external surface 204b of the tubular expansion cone 204. In particular, the intermediate non pre-expanded portion 206c of the expandable tubular member 206 is radially expanded and plastically deformed off of the tapered external surface 204b of the tubular expansion cone 204. As a result, the sealing member 206e engages the interior surface of the wellbore casing 104. Consequently, the radially expanded intermediate portion 206c of the expandable tubular member 206 is thereby coupled to the wellbore casing 104. The radially expanded intermediate portion 206c of the expandable tubular member 206 is also thereby anchored to the wellbore casing 104.

As illustrated in Fig. 2d, after the expandable tubular member 206 has been plastically deformed and radially expanded off of the tapered external surface 204b of the tubular expansion cone 204, the tubular expansion cone is pulled out of the borehole 224 by applying an upward force to the tubular support member 202. As a result, the second and third expandable tubular members, 214 and 220, are radially expanded and plastically deformed off of the tapered external surface 204b of the tubular expansion cone 204. In particular, the intermediate non pre-expanded portion 214c of the second expandable tubular member 214 is radially expanded and plastically deformed off of the tapered external surface 204b of the tubular expansion cone 204. As a result, the sealing member 214e engages the interior surface of the wellbore 224. Consequently, the radially expanded intermediate portion 214c of the second expandable tubular member 214 is thereby coupled to the wellbore 224. The radially expanded intermediate portion 214c of the second expandable tubular member 214 is also thereby anchored to the wellbore 104. Furthermore, the continued application of the upward force to the tubular member 202 will then displace the tubular expansion cone 204 upwardly into engagement with the pre-expanded end 220a of the third expandable tubular member 220. Finally, the continued application of the upward force to the tubular member 202 will then radially expand and plastically

deform the third expandable tubular member 220 off of the tapered external surface 204b of the tubular expansion cone 204. In particular, the intermediate non pre-expanded portion 220c of the third expandable tubular member 220 is radially expanded and plastically deformed off of the tapered external surface 204b of the tubular expansion cone 204. As a result, the sealing member 220e engages the interior surface of the wellbore 224. Consequently, the radially expanded intermediate portion 220c of the third expandable tubular member 220 is thereby coupled to the wellbore 224. The radially expanded intermediate portion 220c of the third expandable tubular member 220 is also thereby anchored to the wellbore 224. As a result, the water zone 226a and fluidicly isolated from the targeted oil sand zone 226b.

After completing the radial expansion and plastic deformation of the third expandable tubular member 220, the tubular support member 202 and the tubular expansion cone 204 are removed from the wellbore 224.

Thus, during the operation of the system 10, the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, respectively, are radially expanded and plastically deformed by the upward displacement of the tubular expansion cone 204. As a result, the sealing members, 206e, 214e, and 220e, are displaced in the radial direction into engagement with the wellbore 224 thereby coupling the shoe 208, the expandable tubular member 206, the slotted tubular members, 210 and 212, the expandable tubular member 214, the slotted tubular members, 216 and 218, and the expandable tubular member 220 to the wellbore. Furthermore, as a result, the connections between the expandable tubular members, 206, 214, and 220, the shoe 208, and the slotted tubular members, 210, 212, 216, and 218, do not have to be expandable connections thereby providing significant cost savings. In addition, the inside diameters of the expandable tubular members, 206, 214, and 220, and the slotted tubular members, 210, 212, 216, and 218, after the radial expansion process, are substantially equal. In this manner, additional conventional tools and other conventional equipment may be easily positioned within, and moved through, the expandable and slotted tubular members. The conventional tools and equipment include conventional valving and other conventional flow control devices for controlling the flow of fluidic materials within and between the expandable tubular members, 206, 214, and 220, and the slotted tubular members, 210, 212, 216, and 218.

Furthermore, in the system 200, the slotted tubular members 210, 212, 216, and 218 are interleaved among the expandable tubular members, 206, 214, and 220. As a result, because only the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, respectively, are radially expanded and plastically defomed, the slotted tubular members, 210, 212, 216, and 218 can be conventional slotted tubular members thereby significantly reducing the cost and complexity of the system 10. Moreover, because only the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, respectively, are radially expanded and plastically deformed, the number and length of the interleaved slotted tubular members, 210, 212, 216, and 218 can be much greater than the number and length of the expandable tubular members. The total length of the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, is approximately 61 m (200 feet), and the total length of the slotted tubular members, 210, 212, 216, and 218, is approximately 1158 m (3800 feet). Consequently, A system 200 having a total length of approximately 1219 m (4000 feet) is coupled to the wellbore 224 by radially expanding and plastically deforming a total length of only approximately 61 m (200 feet).

Furthermore, the sealing members 206e, 214e, and 220e, of the expandable tubular members, 206, 214, and 220, respectively, are used to couple the expandable tubular members and the slotted tubular members, 210, 212, 216, and 218 to the wellbore 224, the radial gap between the slotted tubular members, the expandable tubular members, and the wellbore 224 may be large enough to effectively eliminate the possibility of damage to the expandable tubular members and slotted tubular members during the placement of the system 200 within the wellbore.

The pre-expanded ends, 206a, 206d, 214a, 214d, 220a, and 220d, of the expandable tubular members, 206, 214, and 220, respectively, and the slotted tubular members, 210, 212, 216, and 218, have outside diameters and wall thicknesses of 213 mm (8.375 inches) and 8.89 mm (0.350 inches), respectively; prior to the radial expansion, the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, respectively, have outside diameters of 194 mm (7.625 inches); the slotted tubular members, 210, 212, 216, and 218, have inside diameters of 195 mm (7.675 inches); after the radial expansion, the inside diameters of the intermediate portions, 206c, 214c, and 220c, of the expandable

tubular members, 206, 214, and 220, are equal to 195 mm (7.675 inches); and the wellbore 224 has an inside diameter of 222 mm (8.755 inches).

The pre-expanded ends, 206a, 206d, 214a, 214d, 220a, and 220d, of the expandable tubular members, 206, 214, and 220, respectively, and the slotted tubular members, 210, 212, 216, and 218, have outside diameters and wall thicknesses of 114 mm (4.500 inches) and 6.35 mm (0.250 inches), respectively; prior to the radial expansion, the intermediate non pre-expanded portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, respectively, have outside diameters of 102 mm (4.000 inches); the slotted tubular members, 210, 212, 216, and 218, have inside diameters of 102 mm (4.000 inches); after the radial expansion, the inside diameters of the intermediate portions, 206c, 214c, and 220c, of the expandable tubular members, 206, 214, and 220, are equal to 102 mm (4.000 inches); and the wellbore 224 has an inside diameter of 124 mm (4.892 inches).

The system 200 is used to inject or extract fluidic materials such as, for example, oil, gas, and/or water into or from the subterranean formation 226b.

Referring now to Fig. 3, another expandable tubular member 300 will now be described. The tubular member 300 defines an interior region 300a and includes a first end 300b including a first threaded connection 300ba, a first tapered portion 300c, an intermediate portion 300d, a second tapered portion 300e, and a second end 300f including a second threaded connection 300fa. The tubular member 300 further preferably includes an intermediate sealing member 300g that is coupled to the exterior surface of the intermediate portion 300d.

The tubular member 300 has a substantially annular cross section. The tubular member 300 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or L83, J55, or P110 API casing.

The interior 300a of the tubular member 300 has a substantially circular cross section. Furthermore, The interior region 300a of the tubular member includes a first inside diameter D_1, an intermediate inside diameter D_{INT}, and a second inside diameter D_2. The first and second inside diameters, D_1 and D_2, are substantially equal. The first and second inside diameters, D_1 and D_2, are greater than the intermediate inside diameter D_{INT}.

The first end 300b of the tubular member 300 is coupled to the intermediate portion 300d by the first tapered portion 300c, and the second end 300f of the tubular

member is coupled to the intermediate portion by the second tapered portion 300e. The outside diameters of the first and second ends, 300b and 300f, of the tubular member 300 is greater than the outside diameter of the intermediate portion 300d of the tubular member. The first and second ends, 300b and 300f, of the tubular member 300 include wall thicknesses, t_1 and t_2, respectively. The outside diameter of the intermediate portion 300d of the tubular member 300 ranges from about 75% to 98% of the outside diameters of the first and second ends, 300a and 300f. The intermediate portion 300d of the tubular member 300 includes a wall thickness t_{INT}.

The wall thicknesses t_1 and t_2 are substantially equal in order to provide substantially equal burst strength for the first and second ends, 300a and 300f, of the tubular member 300. The wall thicknesses, t_1 and t_2, are both greater than the wall thickness t_{INT} in order to optimally match the burst strength of the first and second ends, 300a and 300f, of the tubular member 300 with the intermediate portion 300d of the tubular member 300.

The first and second tapered portions, 300c and 300e, may be inclined at an angle, α, relative to the longitudinal direction ranging from about 0 to 30 degrees in order to optimally facilitate the radial expansion of the tubular member 300. The first and second tapered portions, 300c and 300e, provide a smooth transition between the first and second ends, 300a and 300f, and the intermediate portion 300d, of the tubular member 300 in order to minimize stress concentrations.

The intermediate sealing member 300g is coupled to the outer surface of the intermediate portion 300d of the tubular member 300. The intermediate sealing member 300g seals the interface between the intermediate portion 300d of the tubular member 300 and the interior surface of a wellbore casing 305, or other preexisting structure, after the radial expansion and plastic deformation of the intermediate portion 300d of the tubular member 300. The intermediate sealing member 300g has a substantially annular cross section. The outside diameter of the intermediate sealing member 300g is selected to be less than the outside diameters of the first and second ends, 300a and 300f, of the tubular member 300 in order to optimally protect the intermediate sealing member 300g during placement of the tubular member 300 within the wellbore casings 305. The intermediate sealing member 300g may be fabricated from any number of conventional commercially available materials such as, for example, thermoset or thermoplastic polymers. The intermediate sealing member 300g is fabricated from thermoset polymers in order to optimally seal the radially

expanded intermediate portion 300d of the tubular member 300 with the wellbore casing 305. The sealing member 300g may include one or more rigid anchors for engaging the wellbore casing 305 to thereby anchor the radially expanded and plastically deformed intermediate portion 300d of the tubular member 300 to the wellbore casing.

Referring to Figs. 4, and 5a to 5d, The tubular member 300 is formed by a process 400 that includes the steps of: (1) upsetting both ends of a tubular member in step 405; (2) expanding both upset ends of the tubular member in step 410; (3) stress relieving both expanded upset ends of the tubular member in step 415; (4) forming threaded connections in both expanded upset ends of the tubular member in step 420; and (5) putting a sealing material on the outside diameter of the non-expanded intermediate portion of the tubular member in step 425.

As illustrated in FIG. 5a, in step 405, both ends, 500a and 500b, of a tubular member 500 are upset using conventional upsetting methods. The upset ends, 500a and 500b, of the tubular member 500 include the wall thicknesses t_1 and t_2. The intermediate portion 500c of the tubular member 500 includes the wall thickness t_{INT} and the interior diameter D_{INT}. The wall thicknesses t_1 and t_2 are substantially equal in order to provide burst strength that is substantially equal along the entire length of the tubular member 500. The wall thicknesses t_1 and t_2 are both greater than the wall thickness t_{INT} in order to provide burst strength that is substantially equal along the entire length of the tubular member 500, and also to optimally facilitate the formation of threaded connections in the first and second ends, 500a and 500b.

As illustrated in Fig. 5b, in steps 410 and 415, both ends, 500a and 500b, of the tubular member 500 are radially expanded using conventional radial expansion methods, and then both ends, 500a and 500b, of the tubular member are stress relieved. The radially expanded ends, 500a and 500b, of the tubular member 500 include the interior diameters D_1 and D_2. The interior diameters D_1 and D_2 are substantially equal in order to provide a burst strength that is substantially equal. The ratio of the interior diameters D_1 and D_2 to the interior diameter D_{INT} ranges from about 100% to 120% in order to facilitate the subsequent radial expansion of the tubular member 500.

The relationship between the wall thicknesses t_1, t_2, and t_{INT} of the tubular member 500; the inside diameters D_1, D_2 and D_{INT} of the tubular member 500; the inside diameter $D_{wellbore}$ of the wellbore casing, or other structure, that the tubular

member 500 will be inserted into; and the outside diameter D_{cone} of the expansion cone that will be used to radially expand the tubular member 500 within the wellbore casing is given by the following expression:

$$Dwellbore - 2 * t_1 \geq \frac{1}{t_1} \left[(t_1 - t_{INT}) * D_{cone} + t_{INT} * D_{INT} \right]$$

where $t_1 = t_2$; and

$D_1 = D_2$.

By satisfying the relationship given in equation (1), the expansion forces placed upon the tubular member 500 during the subsequent radial expansion process are substantially equalized. More generally, the relationship given in equation (1) may be used to calculate the optimal geometry for the tubular member 500 for subsequent radial expansion and plastic deformation of the tubular member 500 for fabricating and/or repairing a wellbore casing, a pipeline, or a structural support.

As illustrated in FIG. 5c, in step 420, conventional threaded connections, 500d and 500e, are formed in both expanded ends, 500a and 500b, of the tubular member 500. The threaded connections, 500d and 500e, are provided using conventional processes for forming pin and box type threaded connections available from Atlas-Bradford.

As illustrated in Fig. 5d, in step 425, a sealing member 500f is then applied onto the outside diameter of the non-expanded intermediate portion 500c of the tubular member 500. The sealing member 500f may be applied to the outside diameter of the non-expanded intermediate portion 500c of the tubular member 500 using any number of conventional commercially available methods. The sealing member 500f is applied to the outside diameter of the intermediate portion 500c of the tubular member 500 using commercially available chemical and temperature resistant adhesive bonding.

The expandable tubular members, 206, 214, and 220, of the system 200 may be substantially identical to, and/or incorporate one or more of the teachings of, the tubular members 300 and 500.

Referring to Fig. 6, a tubular expansion cone 600 for radially expanding the tubular members 206, 214, 220, 300 and 500 will now be described. The expansion cone 600 defines a passage 600a and includes a front end 605, a rear end 610, and a radial expansion section 615.

The radial expansion section 615 includes a first conical outer surface 620 and a second conical outer surface 625. The first conical outer surface 620 includes an angle

of attack α_1 and the second conical outer surface 625 includes an angle of attack α_2. The angle of attack α_1 is greater than the angle of attack α_2. In this manner, the first conical outer surface 620 optimally radially expands the intermediate portions, 206c, 214c, 220c, 300d, and 500c, of the tubular members, 206, 214, 220, 300, and 500, and the second conical outer surface 525 optimally radially expands the pre-expanded first and second ends, 206a and 206d, 214a and 214d, 220a and 220d, 300b and 300f, and 500a and 500b, of the tubular members, 206, 214, 220, 300 and 500. The first conical outer surface 620 includes an angle of attack α_1 ranging from about 8 to 20 degrees, and the second conical outer surface 625 includes an angle of attack α_2 ranging from about 4 to 15 degrees in order to optimally radially expand and plastically deform the tubular members, 206, 214, 220, 300 and 500. More generally, the expansion cone 600 may include 3 or more adjacent conical outer surfaces having angles of attack that decrease from the front end 605 of the expansion cone 600 to the rear end 610 of the expansion cone 600.

Referring to Fig. 7, another tubular expansion cone 700 defines a passage 700a and includes a front end 705, a rear end 710, and a radial expansion section 715. The radial expansion section 715 includes an outer surface having a substantially parabolic outer profile thereby providing a paraboloid shape. In this manner, the outer surface of the radial expansion section 715 provides an angle of attack that constantly decreases from a maximum at the front end 705 of the expansion cone 700 to a minimum at the rear end 710 of the expansion cone. The parabolic outer profile of the outer surface of the radial expansion section 715 may be formed using a plurality of adjacent discrete conical sections and/or using a continuous curved surface. In this manner, the region of the outer surface of the radial expansion section 715 adjacent to the front end 705 of the expansion cone 700 may optimally radially expand the intermediate portions, 206c, 214c, 220c, 300d, and 500c, of the tubular members, 206, 214, 220, 300, and 500, while the region of the outer surface of the radial expansion section 715 adjacent to the rear end 710 of the expansion cone 700 may optimally radially expand the pre-expanded first and second ends, 206a and 206d, 214a and 214d, 220a and 220d, 300b and 300f, and 500a and 500b, of the tubular members, 206, 214, 220, 300 and 500. The parabolic profile of the outer surface of the radial expansion section 715 is selected to provide an angle of attack that ranges from about 8 to 20 degrees in the vicinity of the front end 705 of the expansion cone 700 and an angle of attack in the vicinity of the rear end 710 of the expansion cone 700 from about 4 to 15 degrees.

The tubular expansion cone 204 of the system 200 is substantially identical to the expansion cones 600 or 700, and/or incorporates one or more of the teachings of the expansion cones 600 and/or 700.

The teachings of the apparatus 130, the system 200, the expandable tubular member 300, the method 400, and/or the expandable tubular member 500 may be at least partially combined.

Referring to Fig. 8, conventional temperature, pressure, and flow sensors, 802, 804, and 806, respectively, are operably coupled to the perforated tubulars 145 of the apparatus 130. The temperature, pressure, and flow sensors, 802, 804, and 806, respectively, in turn are operably coupled to a controller 810 that receives and processes the output signals generated by the temperature, pressure, and flow sensors to thereby control the operation of the flow control valves 160 to enhance the operational efficiency of the apparatus 130. The control algorithms utilized by the controller 810 for controlling the operation of the flow control valves 160 as a function of the operating temperature, pressure, and flow rates within the perforated tubular members 145 are conventional.

Referring to Fig. 9, a solid tubular member 905 is coupled to one of the perforated tubular members 145 by radially expanding and plastically deforming the solid tubular member into engagement with the perforated tubular member in a conventional manner and/or using one or more of the radial expansion methods disclosed in one or more of the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on 4/26/2000, (10) PCT patent application serial no. PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed

on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no. 25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999, (18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, (22) U.S. provisional patent application serial no. 60/270,007, attorney docket no. 25791.50, filed on 2/20/2001; (23) U.S. provisional patent application serial no. 60/262,434, attorney docket no. 25791.51, filed on 1/17/2001; (24) U.S, provisional patent application serial no. 60/259,486, attorney docket no. 25791.52, filed on 1/3/2001; (25) U.S. provisional patent application serial no. 60/303,740, attorney docket no. 25791.61, filed on 7/6/2001; (26) U.S. provisional patent application serial no. 60/313,453, attorney docket no. 25791.59, filed on 8/20/2001; (27) U.S. provisional patent application serial no. 60/317,985, attorney docket no. 25791.67, filed on 9/6/2001; (28) U.S. provisional patent application serial no. 60,318,386, attorney docket no. 25791.67.02, filed on 9/10/2001; and (29) U.S. utility patent application serial no. 09/969,922, attorney docket no. 25791.69, filed on 10/3/2001. In this manner, the solid tubular member 905 fluidicly seals the radial passages formed in the perforated tubular member 145 thereby preventing the passage of fluidic materials and/or formation materials through the perforated tubular member.

Referring to Fig. 10, the radial openings in one of the perforated tubular members 145 are sealed by injecting a hardenable fluidic sealing material 1005 into the radial openings in the one perforated tubular member by positioning a closed ended pipe 1010 having one or more radial openings 1010a within the one perforated tubular member 145. Conventional sealing members 1015 and 1020 then seal the interface between the pipe 1010 and the opposite ends of the one perforated tubular member

145. The hardenable fluidic sealing material 1005 is then injected into the radial openings in the one perforated tubular member 145. The sealing members 140 prevent the passage of the hardenable fluidic sealing material out of the annulus between the one perforated tubular member 145 and the formation 125. The pipe 1010 and sealing members, 1015 and 1020, are then removed from the apparatus 130, and the hardenable fluidic sealing material is allowed to cure. A conventional drill string may then be used to remove any excess cured sealing material from the interior surface of the one perforated tubular member 145. The hardenable fluidic sealing material is a curable epoxy resin.

As illustrated in Fig. 11, one or more of the perforated tubular members 145 of the apparatus 130 may be radially expanded and plastically deformed into contact with the surrounding formation 125 thereby compressing the surrounding formation. In this manner, the surrounding formation 125 is maintained in a state of compression thereby stabilizing the surrounding formation, reducing the flow of loose particles from the surrounding formation into the radial openings of the perforated tubular member 145, and enhancing the recovery of hydrocarbons from the surrounding formation.

A seismic source 1105 is positioned on a surface location to thereby impart seismic energy into the formation 125. In this manner, particles lodged in the radial openings in the perforated tubular member 145 may be dislodged from the radial openings thereby enhancing the subsequent recovery of hydrocarbons from the formation 125.

After the perforated tubular member 145 has been radially expanded and plastically formed into contact with the surrounding formation 125, thereby coupling the perforated tubular member 145 to the surrounding formation, an impulsive load is applied to the perforated tubular member. The impulsive load may be applied to the perforated tubular member 145 by applying the load to the end of the apparatus 130. The impulsive load is then transferred to the surrounding formation 125 thereby compacting and/or slurrifying the surrounding formation. As a result, the recovery of hydrocarbons from the formation 125 is enhanced.

As illustrated in Fig. 12, a wellbore casing 1205 having one or more perforations 1210 may be positioned within the wellbore 105 that traverses the formation 125. When the apparatus 130 is positioned within the wellbore 105, one or more of the perforated tubular members 145 of the apparatus 130 are radially expanded and plastically deformed into contact with the wellbore casing 1205 thereby compressing

the surrounding formation 125. In this manner, the surrounding formation 125 is maintained in a state of compression thereby stabilizing the surrounding formation, reducing the flow of loose particles from the surrounding formation into the radial openings of the perforated tubular member 145, and enhancing the recovery of hydrocarbons from the surrounding formation.

A seismic source 1215 is positioned on a surface location to thereby impart seismic energy into the formation 125. In this manner, particles lodged in the radial openings in the perforated tubular member 145 may be dislodged from the radial openings thereby enhancing the subsequent recovery of hydrocarbons from the formation 125.

After the perforated tubular member 145 has been radially expanded and plastically formed into contact with the wellbore casing 1205, thereby coupling the perforated tubular member 145 to the surrounding formation, an impulsive load is applied to the perforated tubular member. The impulsive load may be applied to the perforated tubular member 145 by applying the load to the end of the apparatus 130. The impulsive load is then transferred to the surrounding formation 125 thereby compacting and/or slurrifying the surrounding formation. As a result, the recovery of hydrocarbons from the formation 125 is enhanced.

Referring to Fig. 13, one or more perforated tubular members 1305 are coupled to one of the perforated tubular members 145 by radially expanding and plastically deforming the perforated tubular member into engagement with the perforated tubular member in a conventional manner and/or using one or more of the radial expansion methods disclosed in one or more of the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on 4/26/2000, (10) PCT patent application serial no.

PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no. 25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999, (18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, (22) U.S. provisional patent application serial no. 60/270,007, attorney docket no. 25791.50, filed on 2/20/2001; (23) U.S. provisional patent application serial no. 60/262,434, attorney docket no. 25791.51, filed on 1/17/2001; (24) U.S, provisional patent application serial no. 60/259,486, attorney docket no. 25791.52, filed on 1/3/2001; (25) U.S. provisional patent application serial no. 60/303,740, attorney docket no. 25791.61, filed on 7/6/2001; (26) U.S. provisional patent application serial no. 60/313,453, attorney docket no. 25791.59, filed on 8/20/2001; (27) U.S. provisional patent application serial no. 60/317,985, attorney docket no. 25791.67, filed on 9/6/2001; (28) U.S. provisional patent application serial no. 60/318,386, attorney docket no. 25791.67.02, filed on 9/10/2001; and (29) U.S. utility patent application serial no. 09/969,922, attorney docket no. 25791.69, filed on 10/3/2001. In this manner, the perforated tubular member 905 modifies the flow characteristics of the perforated tubular member 145 thereby permitting the operator of the apparatus 130 to modify the overall flow characteristics of the apparatus.

As illustrated in Fig. 14, a one-way valve 1405 such as, for example, a check valve fluidicly couples the interior of a pair of adjacent perforated tubular members, 145a and 145b, that extract hydrocarbons from corresponding subterranean zones A and B. In this manner, if zone B becomes depleted, hydrocarbons that are being extracted from zone A will not flow into the depleted zone B.

As illustrated in Fig. 15, the apparatus 130 is used to extract geothermal energy from a targeted subterranean geothermal zone 1505. In this manner, the operational efficiency of the extraction of geothermal energy is significantly enhanced due to the increased internal diameters of the various radially expanded elements of the apparatus 130 that permit greater volumetric flows.

The perforated tubular members, 145, 210, 212, 216, 218, and 1305 of the apparatus 130 may be cleaned by further radial expansion of the perforated tubular members. The amount of further radial expansion required to clean the radial passages of the perforated tubular members 145, 210, 212, 216, 218, and 1305 of the apparatus 130 ranged from about 1% to 2%.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. Accordingly, it is appropriate that the appended claims be construed broadly.

1. An apparatus, comprising:

a zonal isolation assembly positioned within a wellbore comprising:

one or more solid tubular members, each solid tubular member including one or more external seals;

one or more perforated tubular members each including a longitudinal and one or more radial passages coupled to the solid tubular members;

one or more flow control valves operably coupled to the perforated tubular members for controlling the flow of fluidic materials through the perforated tubular members;

one or more temperature sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating temperature within the perforated tubular members;

one or more pressure sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating pressure within the perforated tubular members;

one or more flow sensors located within the longitudinal flow passage of one or more of the perforated tubular members for monitoring the operating flow rate within the perforated tubular members;

a controller operably coupled to the flow control valves, the temperature sensors, the pressure sensors, and the flow sensors for monitoring the temperature, pressure and flow sensors and controlling the operation of the flow control valves; and

one or more solid tubular liners coupled to the interior surfaces of one or more of the perforated tubular members for sealing at least some of the radial passages of the perforated tubular members; and

a shoe coupled to the zonal isolation assembly;

wherein at least one of the solid tubular members and the perforated tubular members are formed by a radial expansion process performed within the wellbore; and

wherein the solid tubular liners are formed by a radial expansion process performed within the wellbore.

2. A method of isolating a first subterranean zone from a second subterranean zone in a wellbore, comprising:

positioning one or more solid tubulars within the wellbore, the solid tubulars traversing the first subterranean zone;

positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the second subterranean zone;

radially expanding at least one of the solid tubulars and perforated tubulars within the wellbore;

fluidicly coupling the perforated tubulars and the solid tubulars;

preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid tubulars and perforated tubulars;

monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

3. A method of extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, comprising;

positioning one or more solid tubulars within the wellbore;

positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the producing subterranean zone;

radially expanding at least one of the solid tubulars and the perforated tubulars within the wellbore;

fluidicly coupling the solid tubulars with the casing;

fluidicly coupling the perforated tubulars with the solid tubulars;

fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore;

fluidicly coupling at least one of the perforated tubulars with the producing subterranean zone;

monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

4. A system for isolating a first subterranean zone from a second subterranean zone in a wellbore, comprising:

means for positioning one or more solid tubulars within the wellbore, the solid tubulars traversing the first subterranean zone;

means for positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the second subterranean zone;

means for radially expanding at least one of the solid tubulars and perforated tubulars within the wellbore;

means for fluidicly coupling the perforated tubulars and the solid tubulars;

means for preventing the passage of fluids from the first subterranean zone to the second subterranean zone within the wellbore external to the solid tubulars and perforated tubulars;

means for monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

means for controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

means for positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

means for radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

5. A system for extracting materials from a producing subterranean zone in a wellbore, at least a portion of the wellbore including a casing, comprising;

means for positioning one or more solid tubulars within the wellbore;

means for positioning one or more perforated tubulars each including a longitudinal passage and one or more radial passages within the wellbore, the perforated tubulars traversing the producing subterranean zone;

means for radially expanding at least one of the solid tubulars and the perforated tubulars within the wellbore;

means for fluidicly coupling the solid tubulars with the casing;

means for fluidicly coupling the perforated tubulars with the solid tubulars;

means for fluidicly isolating the producing subterranean zone from at least one other subterranean zone within the wellbore;

means for fluidicly coupling at least one of the perforated tubulars with the producing subterranean zone;

means for monitoring the operating temperatures, pressures, and flow rates within the longitudinal flow passage of one or more of the perforated tubulars;

means for controlling the flow of fluidic materials through the perforated tubulars as a function of the monitored operating temperatures, pressures, and flow rates;

means for positioning one or more solid tubular liners within the interior of one or more of the perforated tubulars; and

means for radially expanding and plastically deforming the solid tubular liners within the interior of one or more of the perforated tubulars to fluidicly seal at least some of the radial passages of the perforated tubulars.

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(72) Inventor(s):
David Paul Brisco
Edwin Arnold Zwald Jr
Chan Daigle
Gregory M Noel
William J Dean
Andrei Gregory Filippov
Ronald D Nida
Robert Lance Cook
Lev Ring
Kevin K Wadell
William Rusty Stephenson
Rune T Gusevik

(73) Proprietor(s):
Shell Internationale Research Maatschappij B.V.
(Incorporated in the Netherlands)
Department IP/43 Carel Van Bylandtlaan 30, 2596 HR The Hague, Netherlands

(74) Agent and/or Address for Service:
Haseltine Lake & Co
Redcliff Quay, 120 Redcliff Street, BRISTOL, BS1 6HU, United Kingdom

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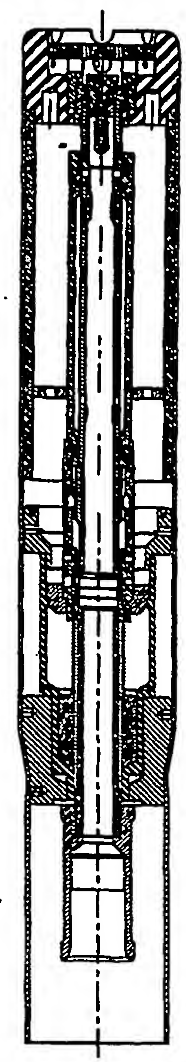

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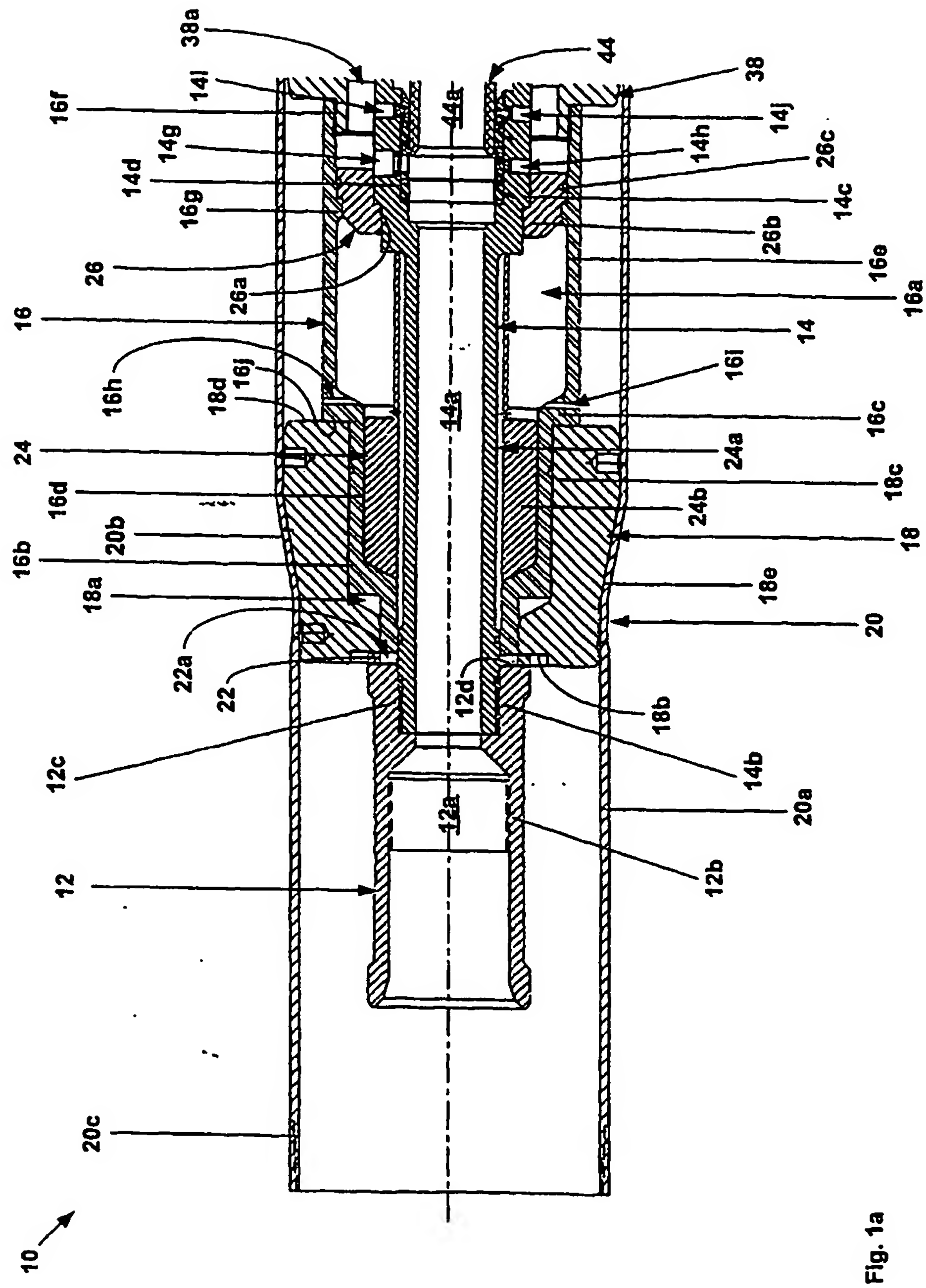
Fig. 1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14
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16i
18d
16j
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16c
24
24a
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16b
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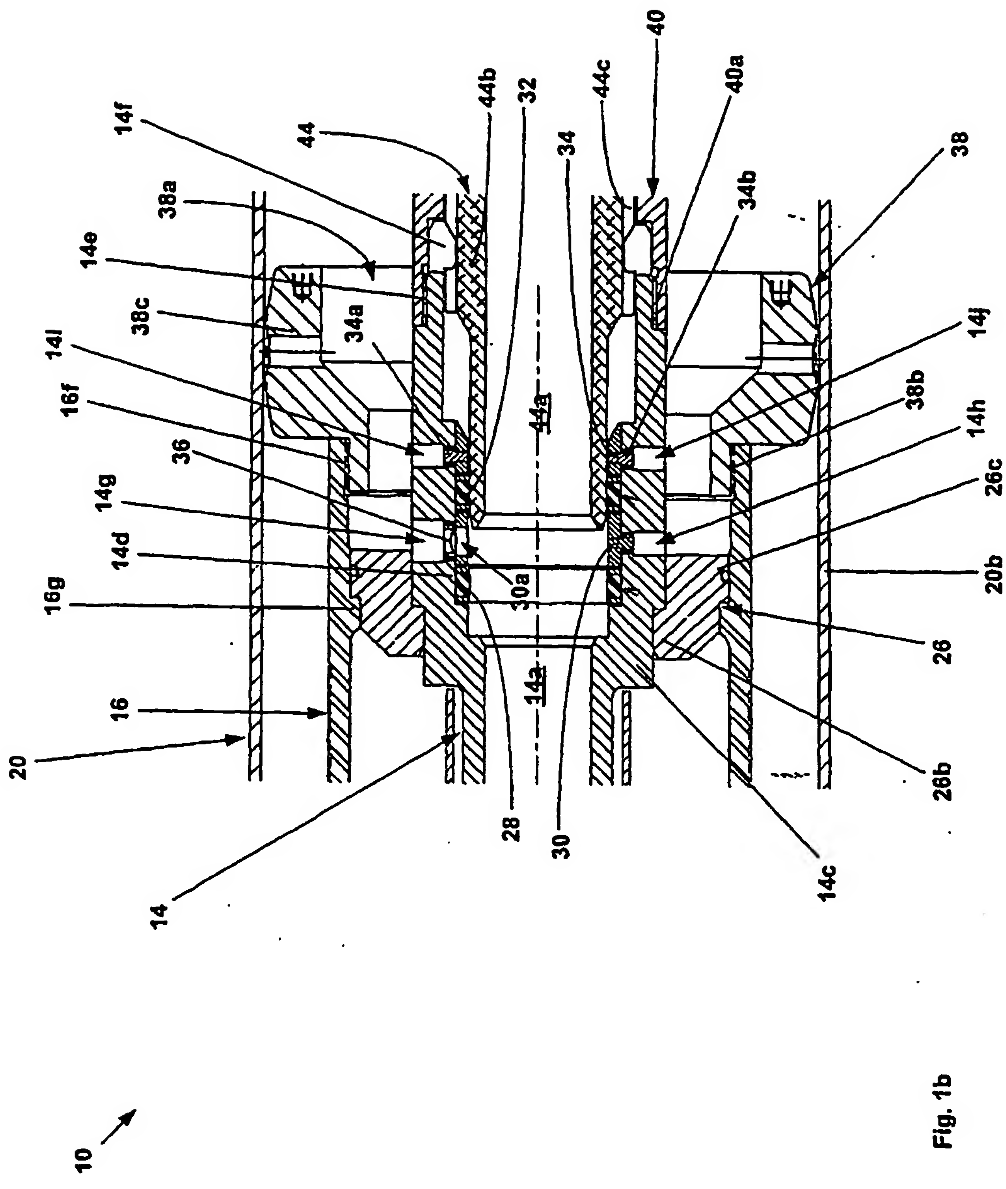
Fig. 1a



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30a
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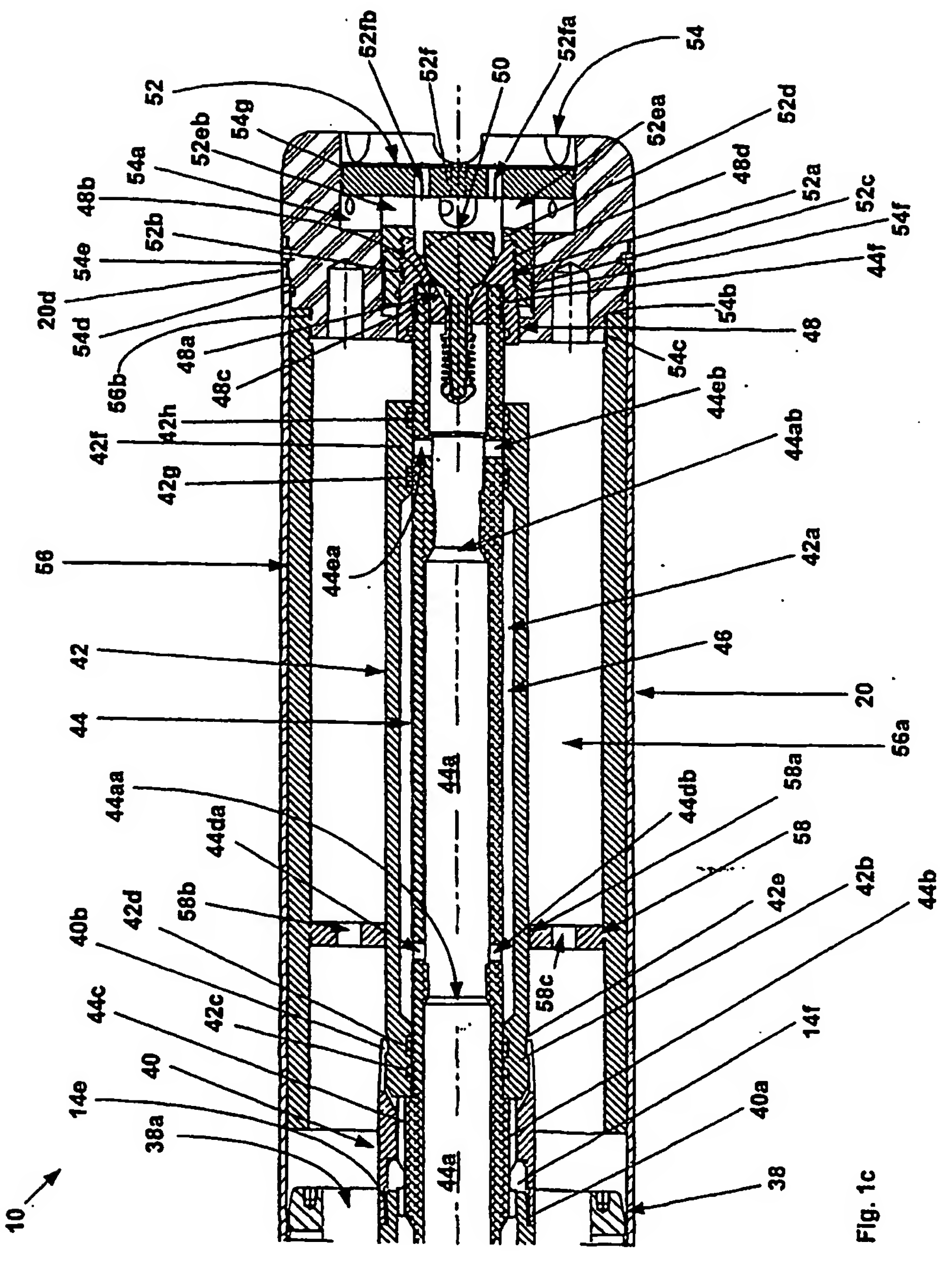
Fig. 1b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20d
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52eb
54g
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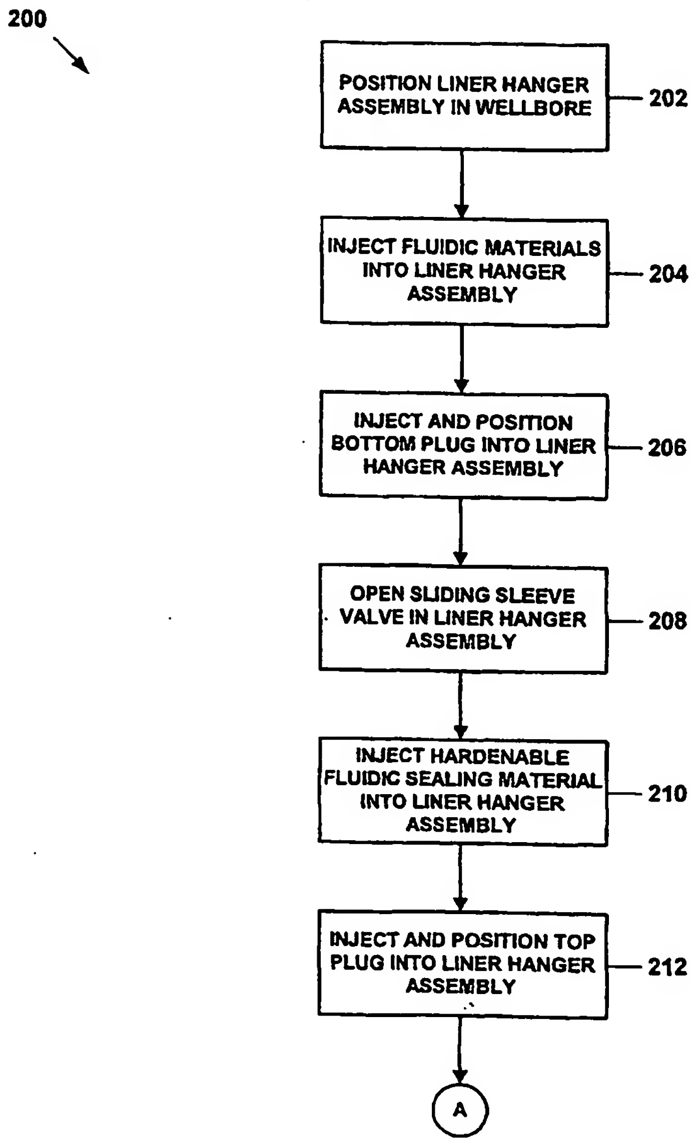
Fig. 1c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POSITION LINER HANGER ASSEMBLY IN WELLBORE
202
INJECT FLUIDIC MATERIALS INTO LINER HANGER ASSEMBLY
204
INJECT AND POSITION BOTTOM PLUG INTO LINER HANGER ASSEMBLY
206
OPEN SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
208
INJECT HARDENABLE FLUIDIC SEALING MATERIAL INTO LINER HANGER ASSEMBLY
210
INJECT AND POSITION TOP PLUG INTO LINER HANGER ASSEMBLY
212
A

Fig. 2a

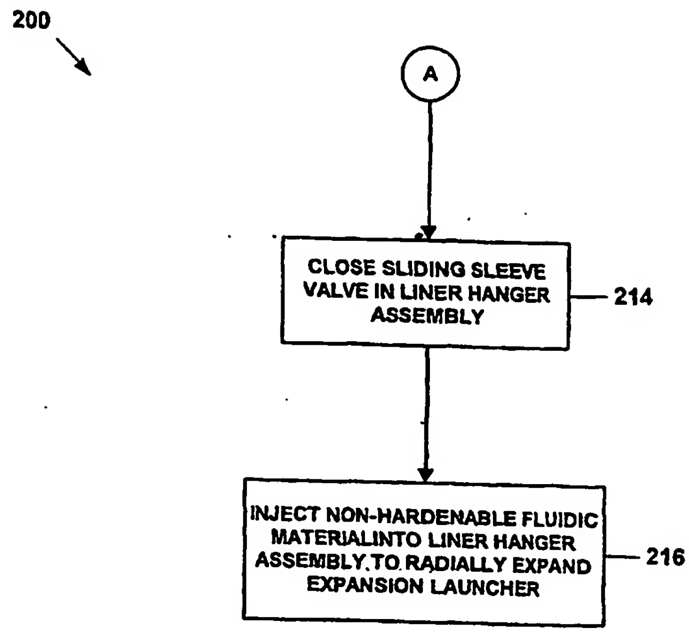
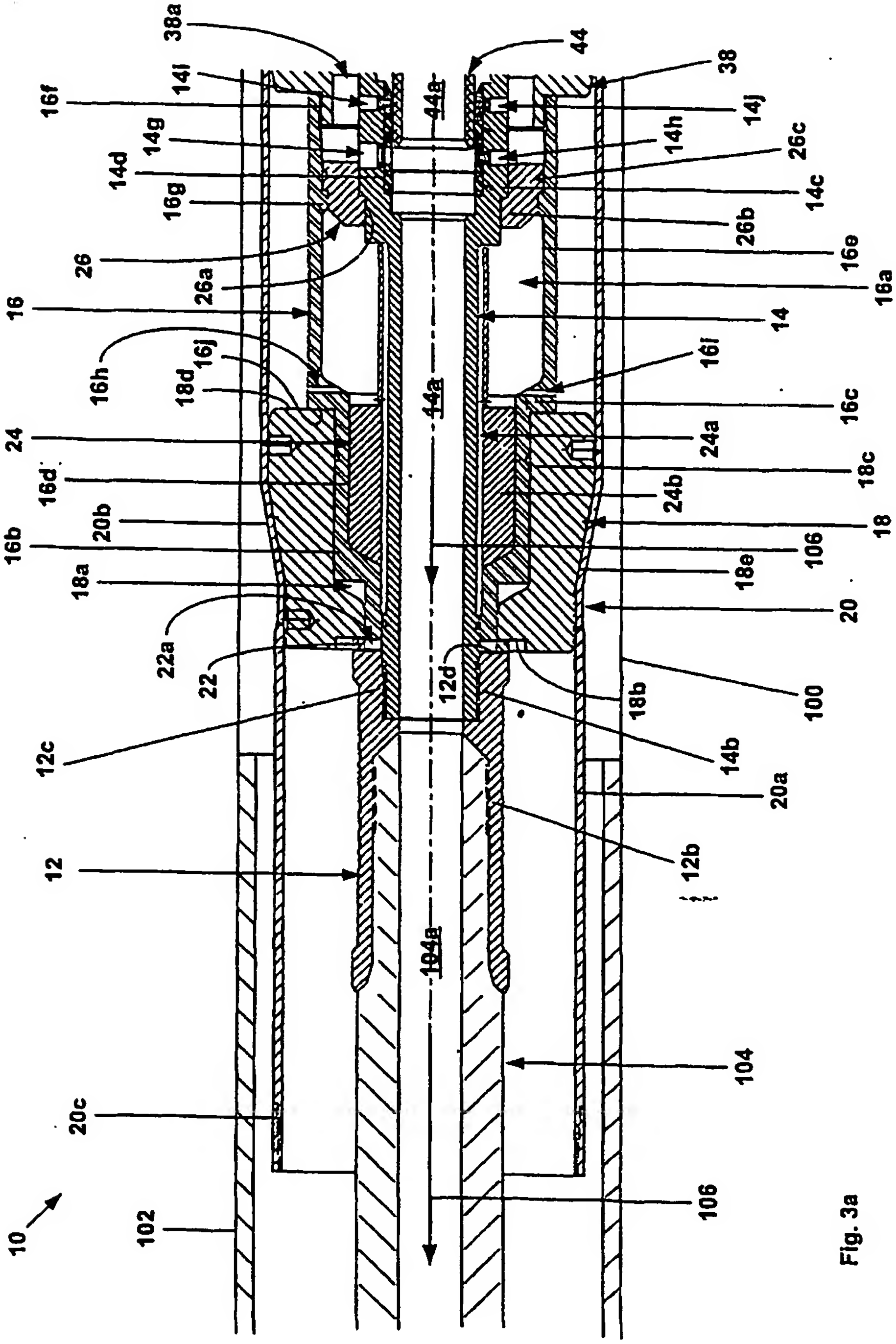

200
A
CLOSE SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
214
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
216

Fig. 2b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16j
18d
16i
16c
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16d
18c
24b
20b
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16b
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18a
18e
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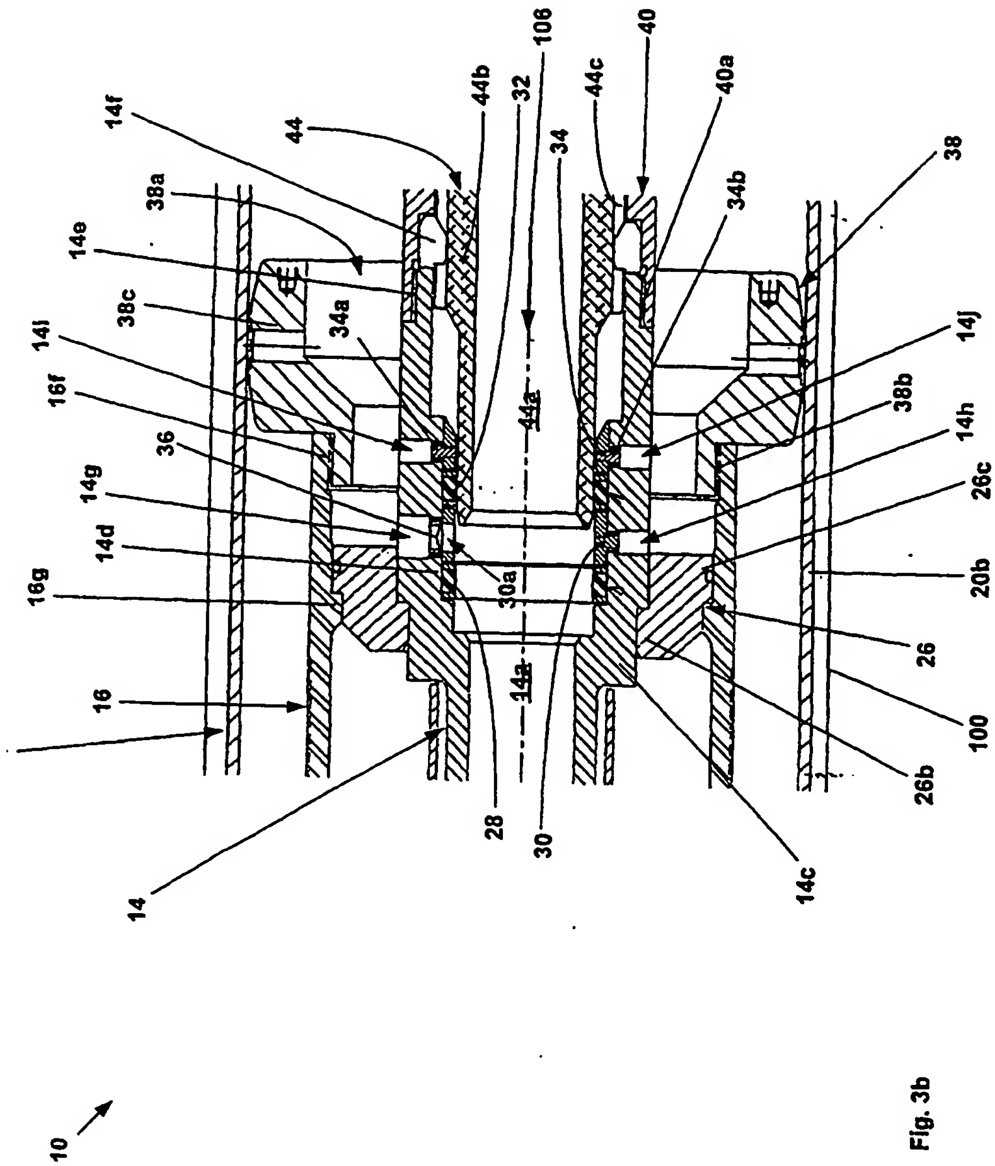
Fig. 3a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16
16g
14d
14g
36
16f
14i
38c
14e
38a
14f
44
44b
32
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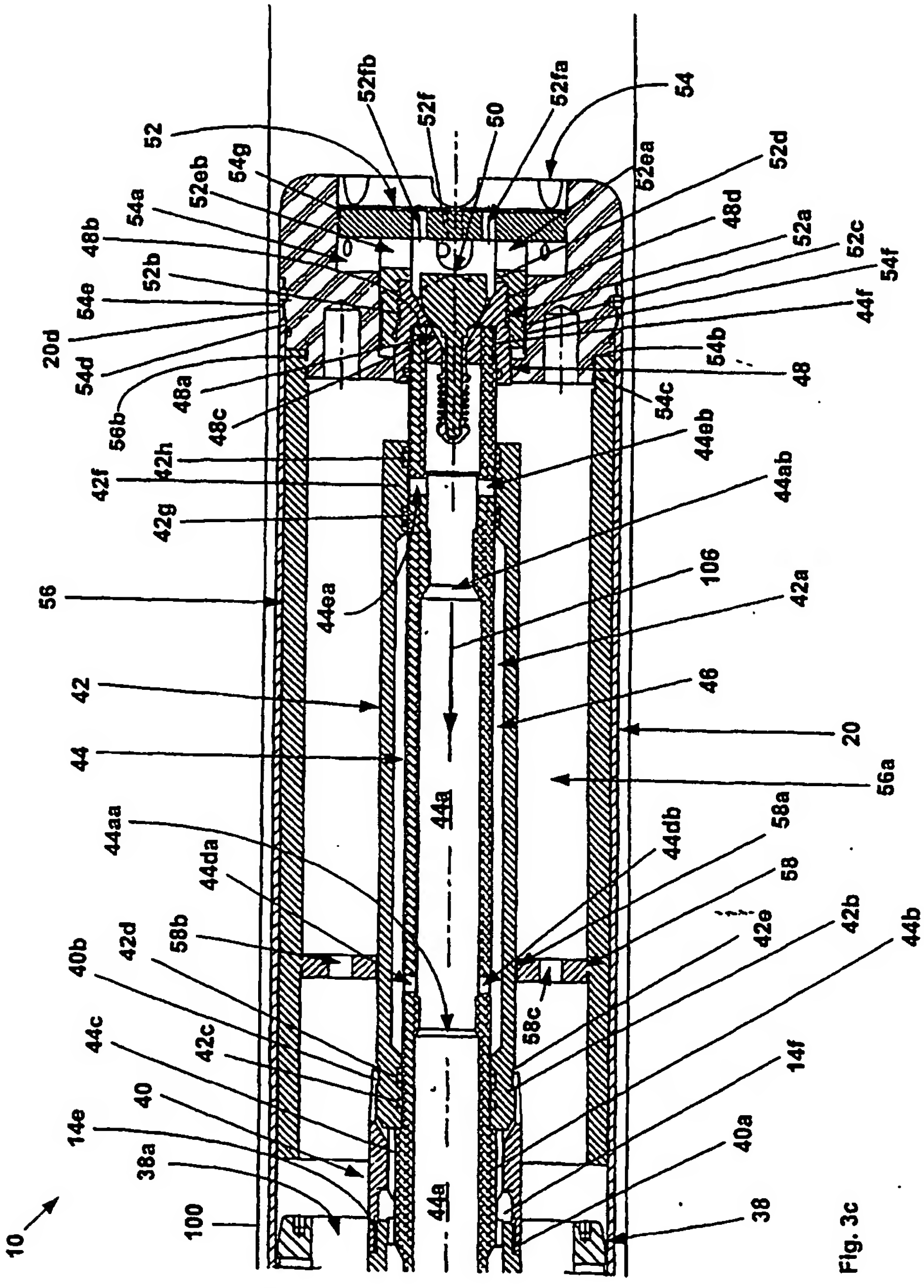
34a
34
44a
44c
40
40a
34b
38
14j
38b
14h
26c
30a
28
14a
30
20b
26
100
26b
14c

Fig. 3b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42d
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44aa
44
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42h
48c
48a
56b
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
50
52fa
54
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
106
42a
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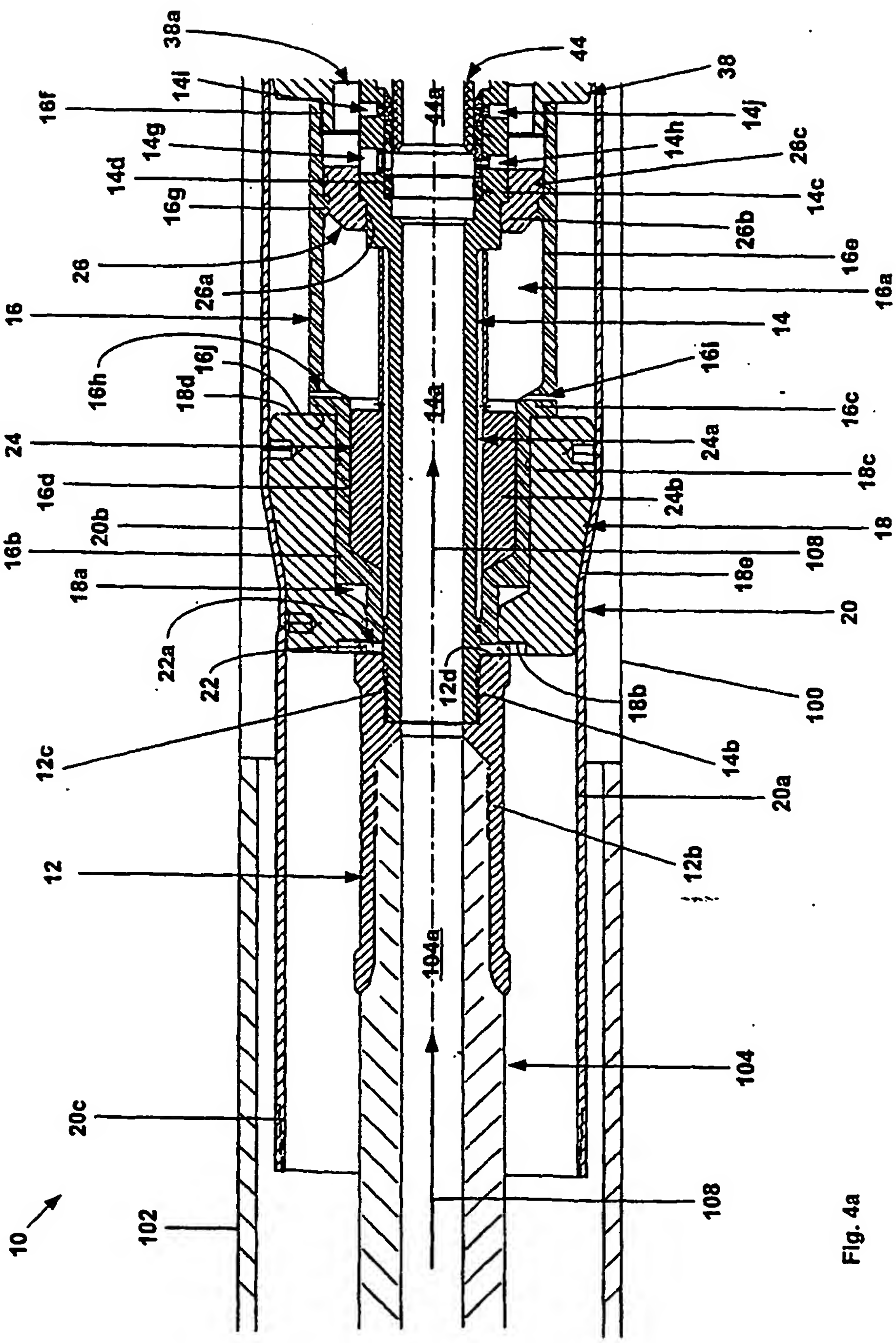
20
56a
44a
44db
58a
58
58c
42e
42b
44b
14f
40a
38

Fig. 3c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18a
16b
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16d
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18d
16j
16h
16
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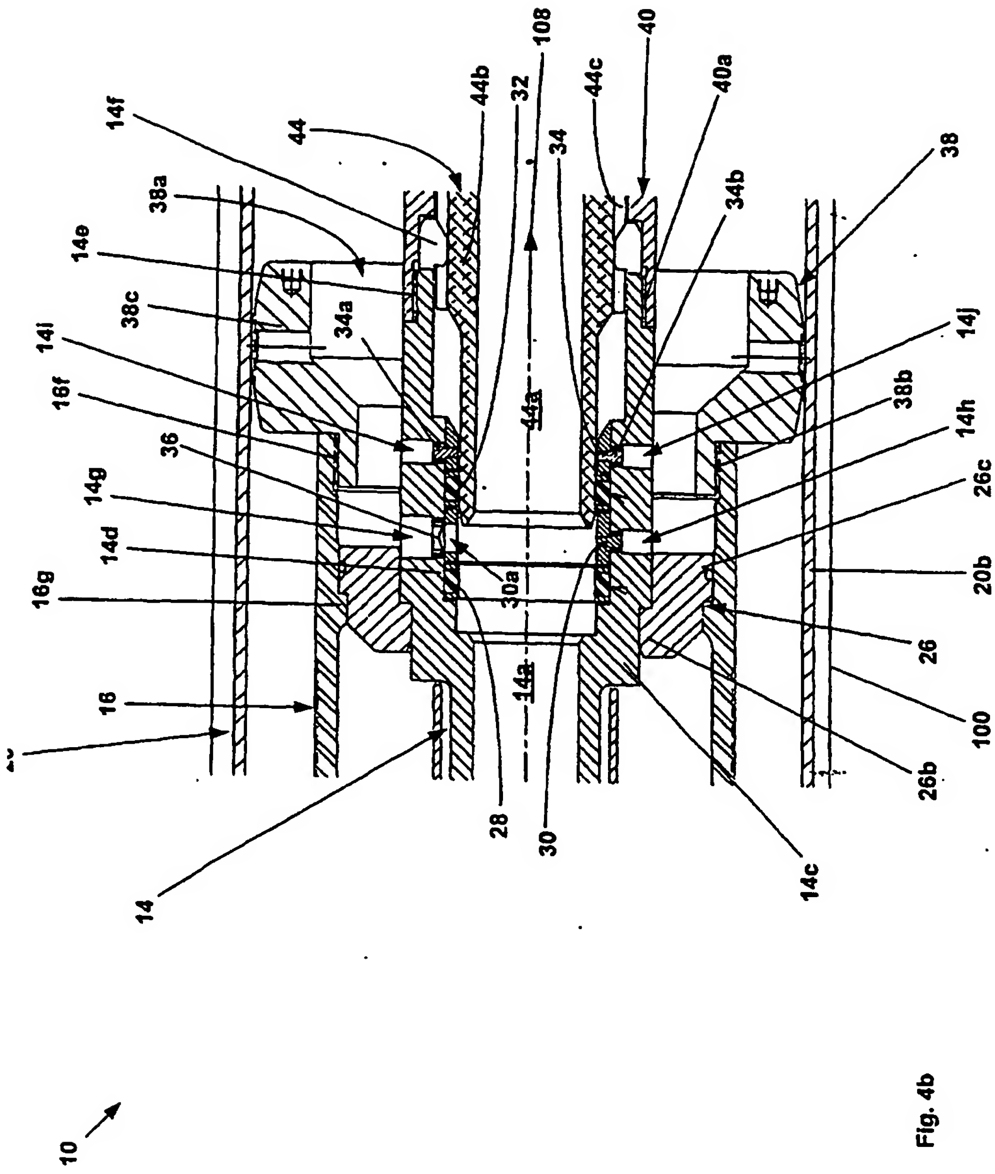
16g
14d
14g
16f
14i
38a
44
44a
14a
104a
108
104
12b
20a
14b
12d
18b
100
20
18e
108
18
24b
18c
24a
16c
16i
14
16a
16e
26b
14c
26c
14h
14j
38

Fig. 4a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38a
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38c
34a
34b
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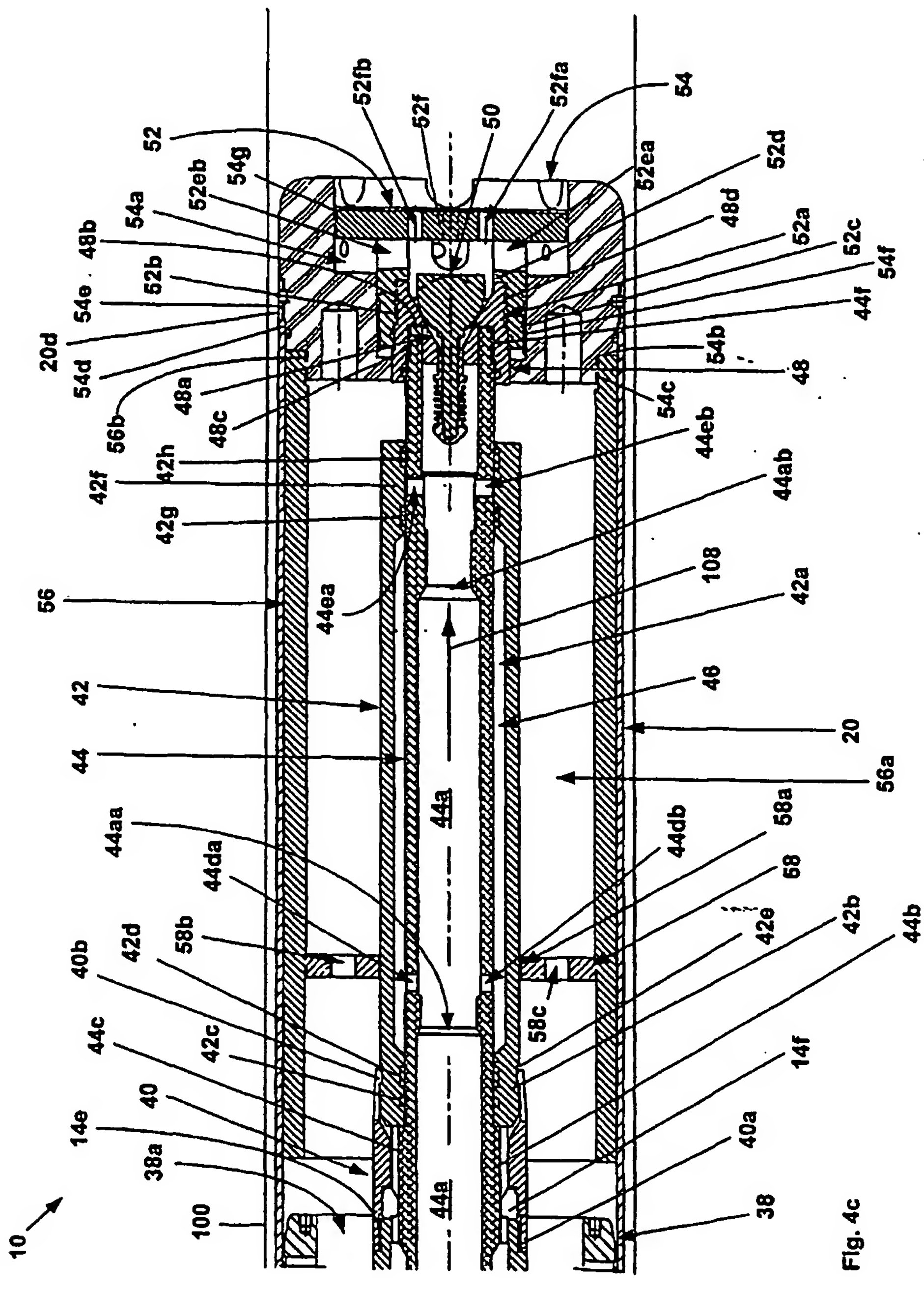
14i
16f
36
14g
14d
16g
16
14
28
30a
30
14c
14j
38b
14h
26c
20b
26
100
26b
44a
14a
10

Fig. 4b



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40b
42d
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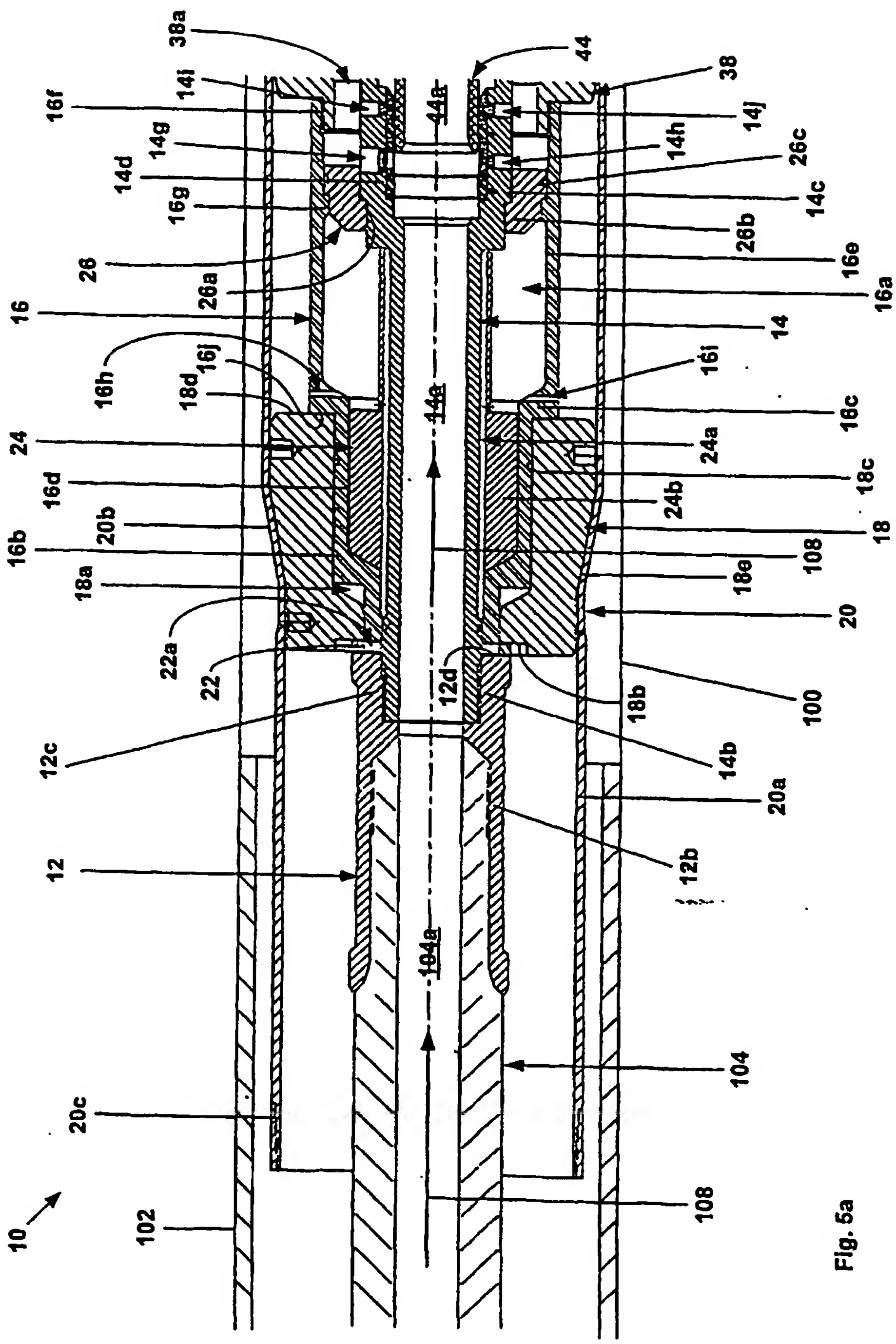
44da
44aa
44
42
56
44ea
42g
42f
42h
56b
48c
48a
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
50
52fa
54
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
108
42a
46
20
56a
44db
58a
58
42e
42b
44b
58c
44a
14f
40a
38

Fig. 4c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14h
14d
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16a
16
14
16h
16j
16i
18d
14a
16c
24
24a
18c
16d
24b
20b
18
16b
108
18a
18e
20
22a
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12d
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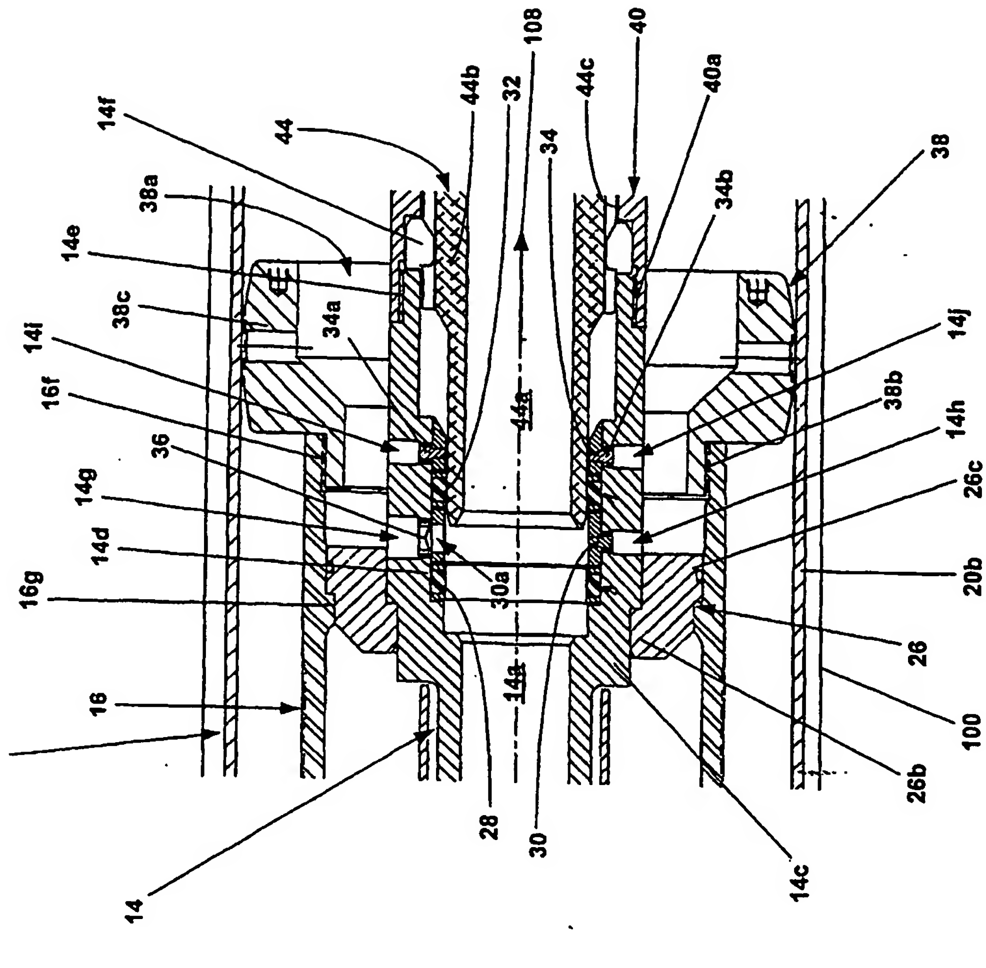
12c
14b
20a
12
12b
104a
104
20c
108
10
102

Fig. 5a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16f
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14e
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14f
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34a
44b
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108
34
44c
40
40a
34b
38
14j
38b
14h
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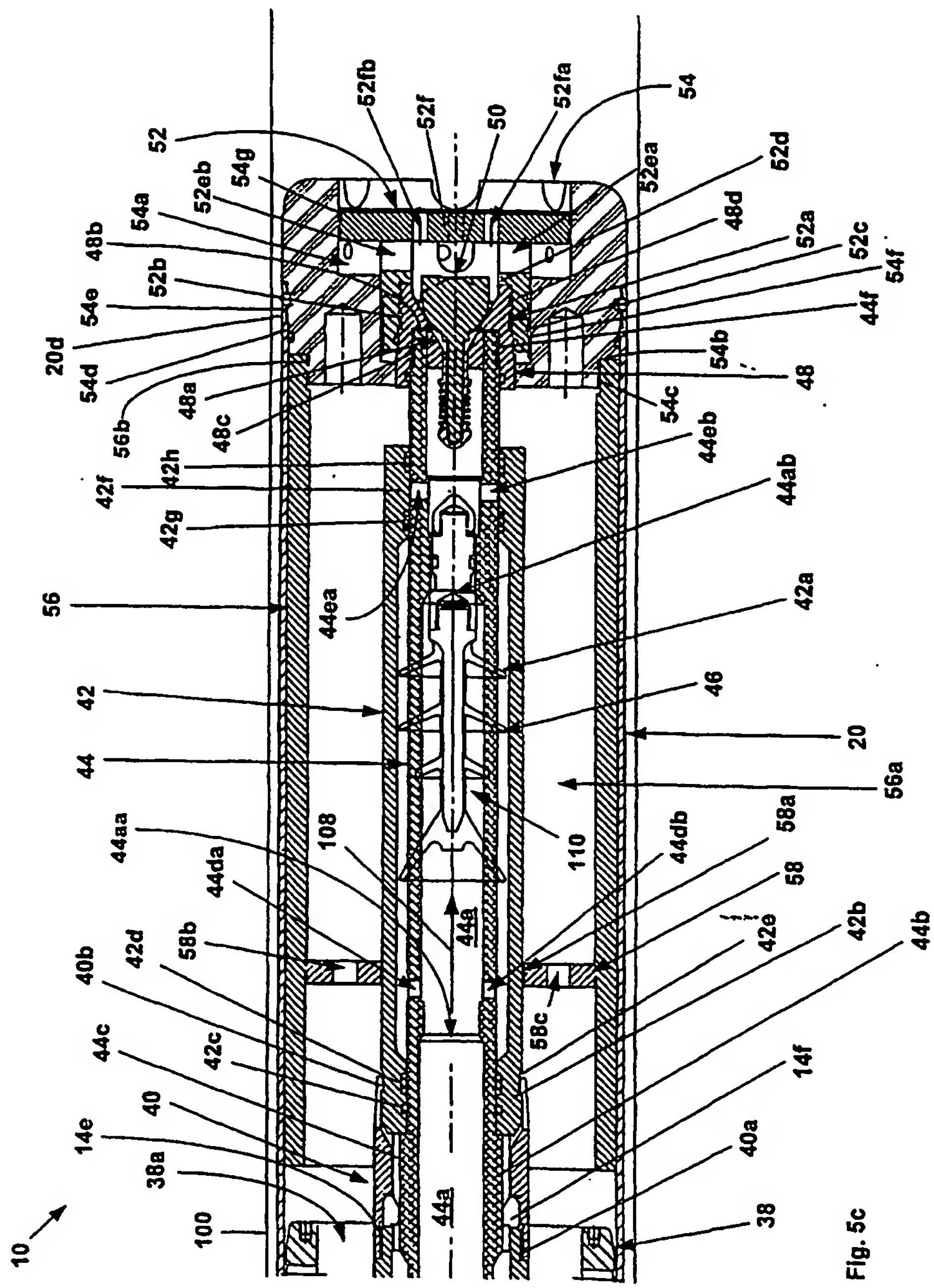
20b
26
100
26b
14c
30
30a
28
14a
44a

Fig. 5b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48b
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54f
54e
44f
20d
54b
54d
48
56b
48a
54c
48c
44eb
42h
42f
44ab
42g
44ea
56
42a
42
46
20
44
56a
110
44aa
108
44db
58a
44da
58
44a
58b
42e
42d
42b
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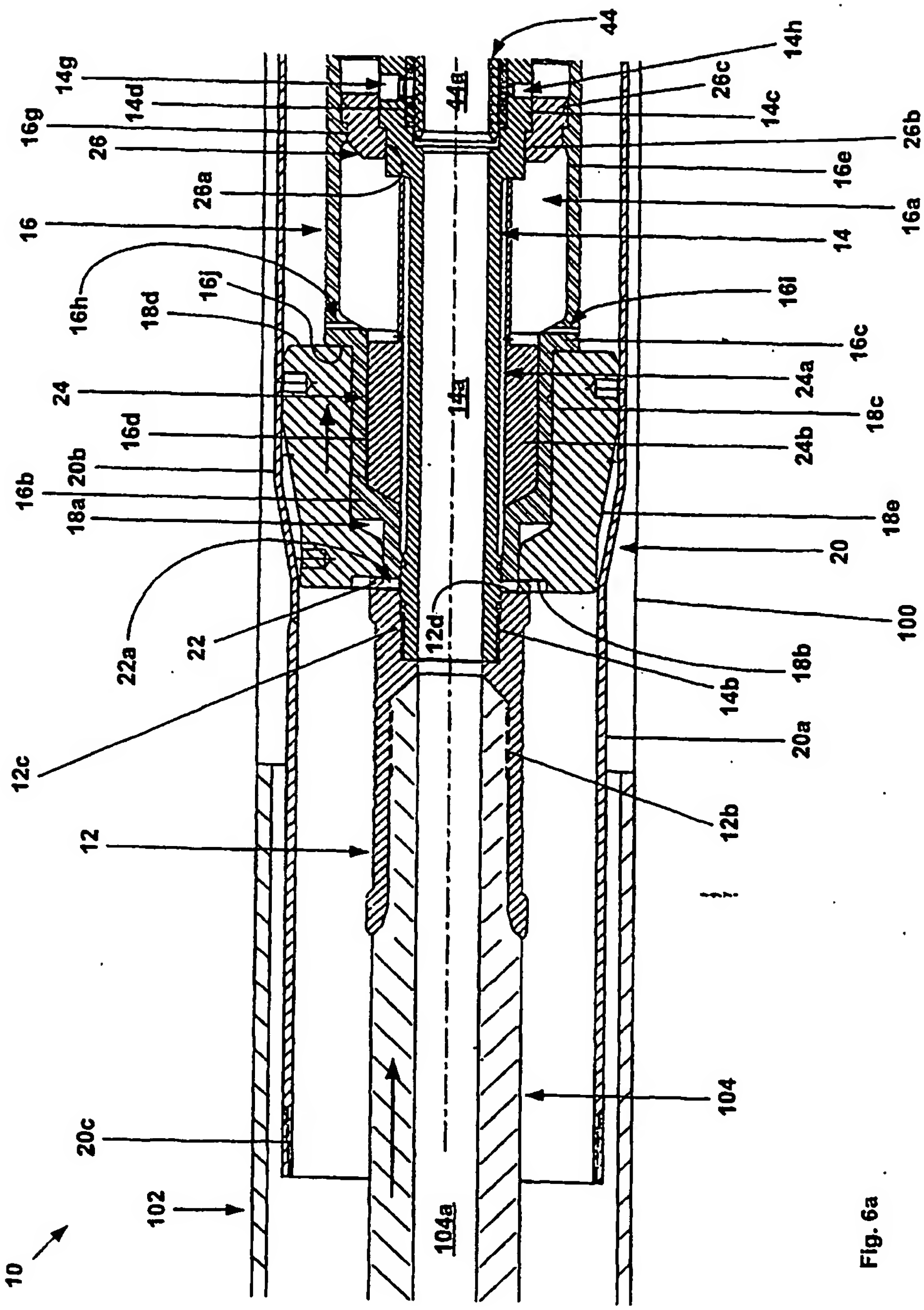
44b
58c
44c
42c
14f
40
40a
14e
38a
44a
38
100
10

Fig. 5c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12
12b
20a
12c
12d
14b
18b
100
22a
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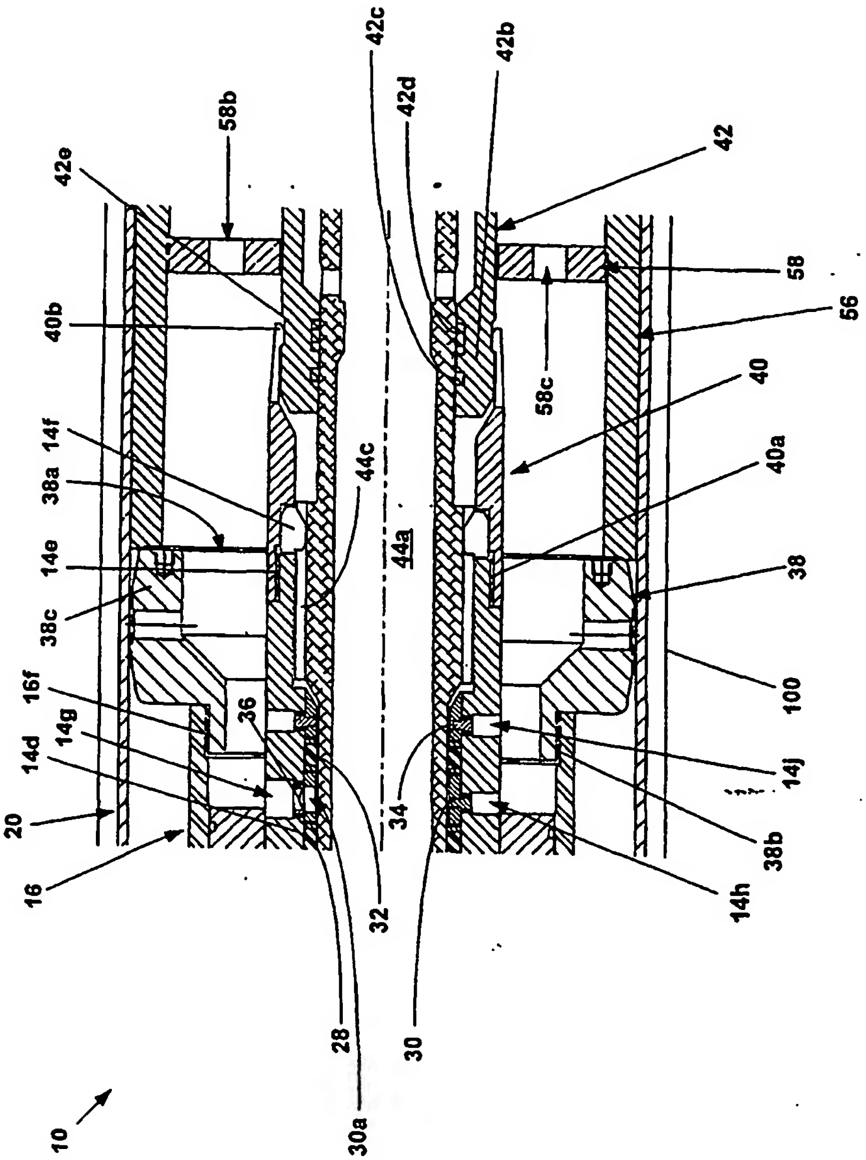
20
18a
18e
16b
20b
24b
16d
18c
24
24a
14a
18d
16c
16h
16j
16i
16
14
16a
26a
16e
26
26b
16g
14c
14d
26c
14g
44a
14h
44

Fig. 6a



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38a
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16f
14g
14d
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16
36
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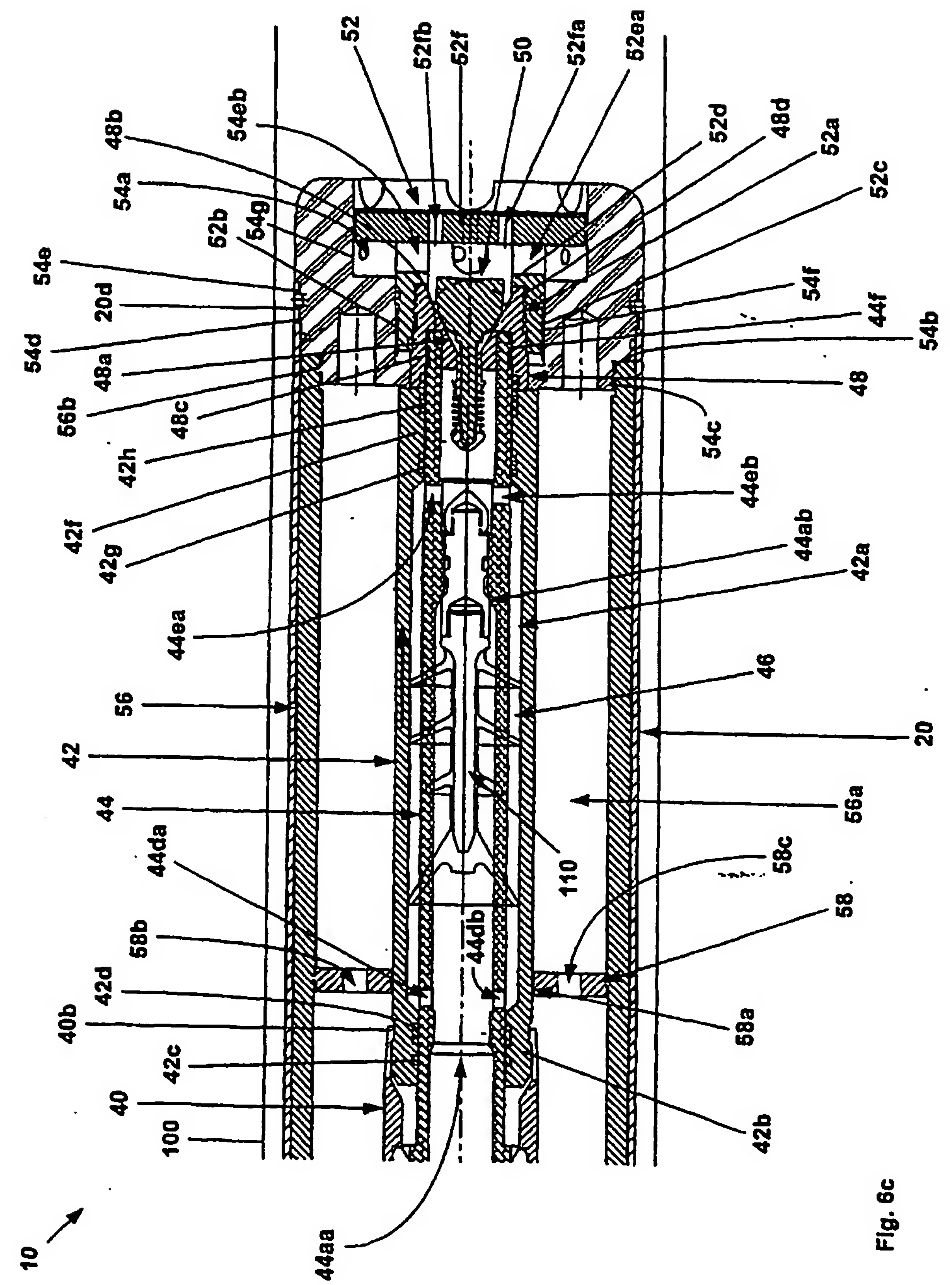
44a
32
28
30a
30
34
42c
42d
42b
42
58
56
58c
40
40a
38
100
14j
38b
14h
10

Fig. 6b



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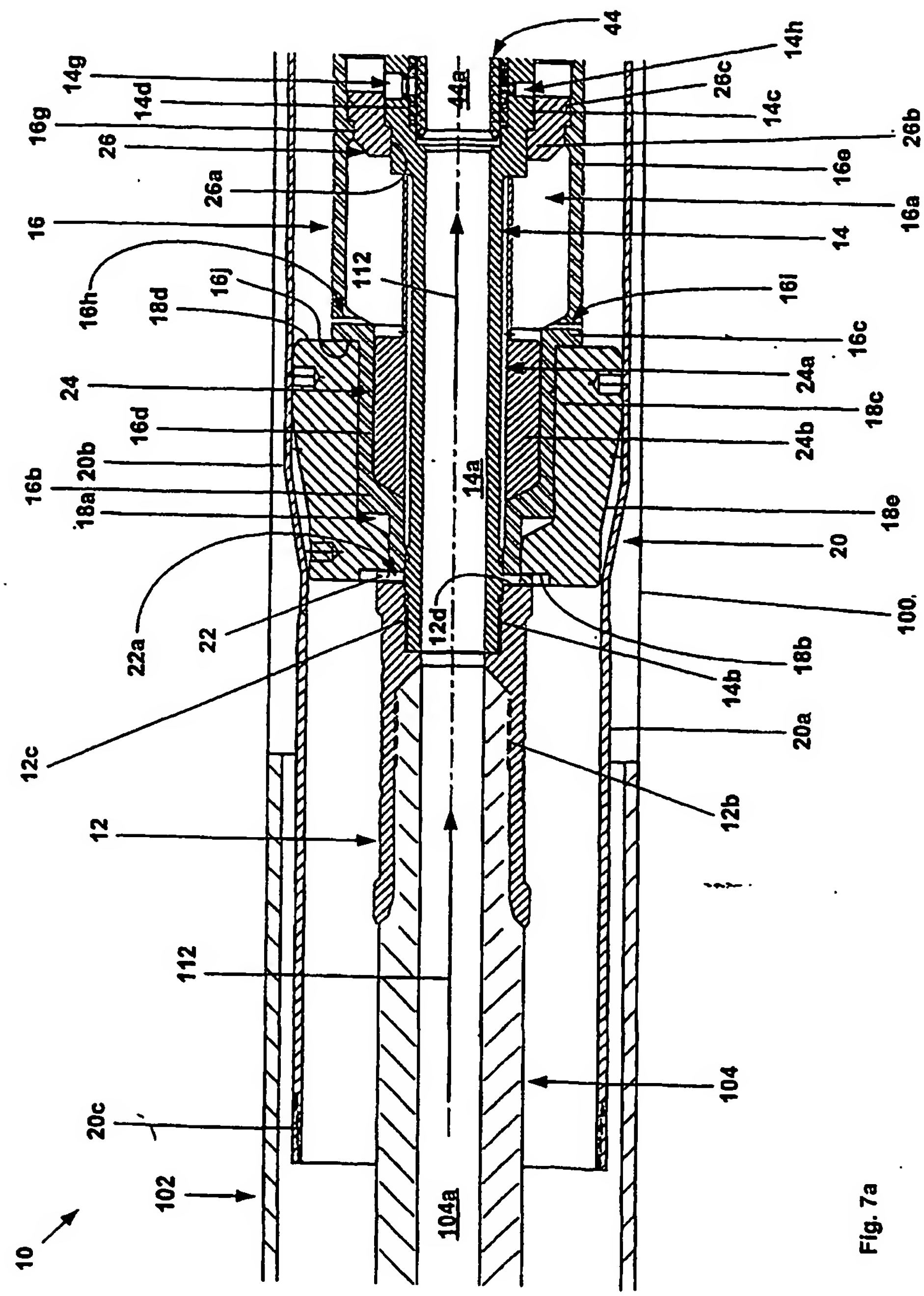
42
56
44ea
42g
42f
42h
48c
56b
48a
54d
20d
54e
52b
54g
54a
48b
54eb
52
52fb
52f
50
52fa
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
46
20
56a
110
58c
58
44db
58a
42b

Fig. 6c



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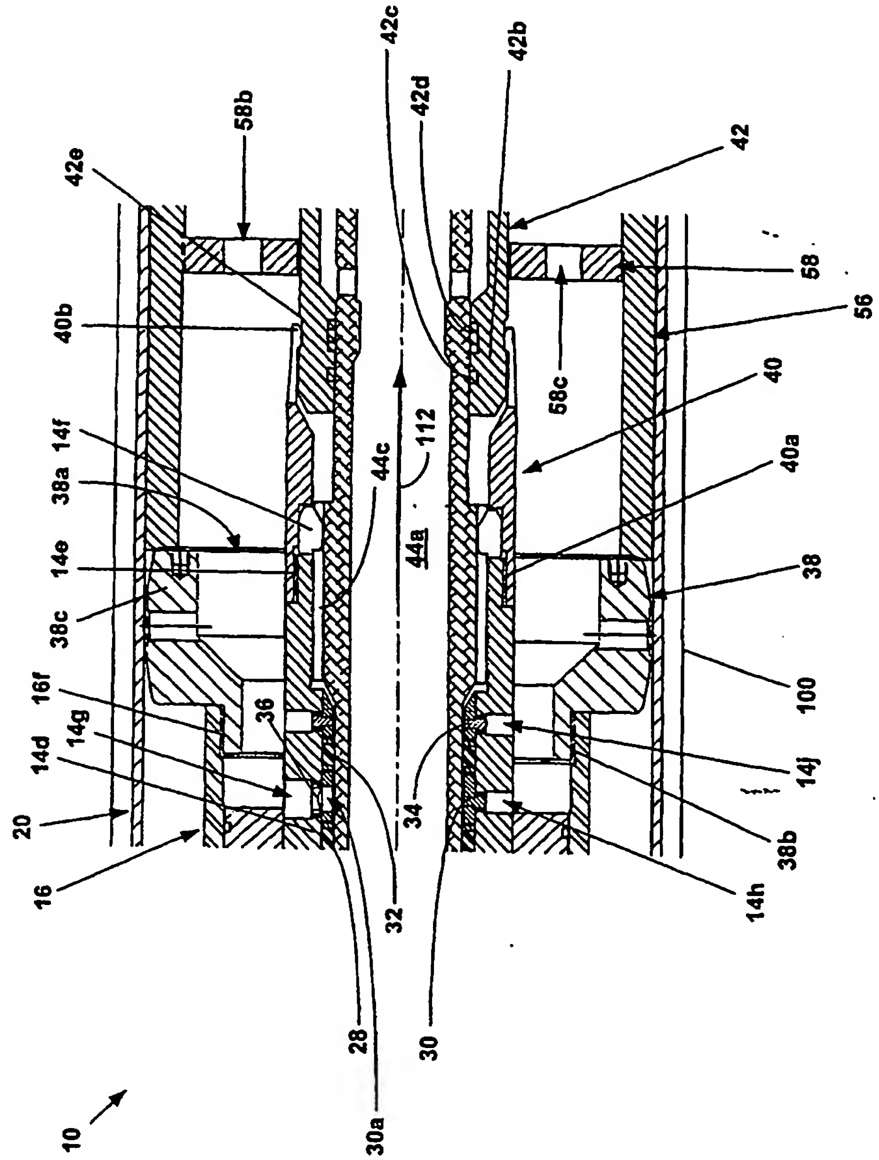
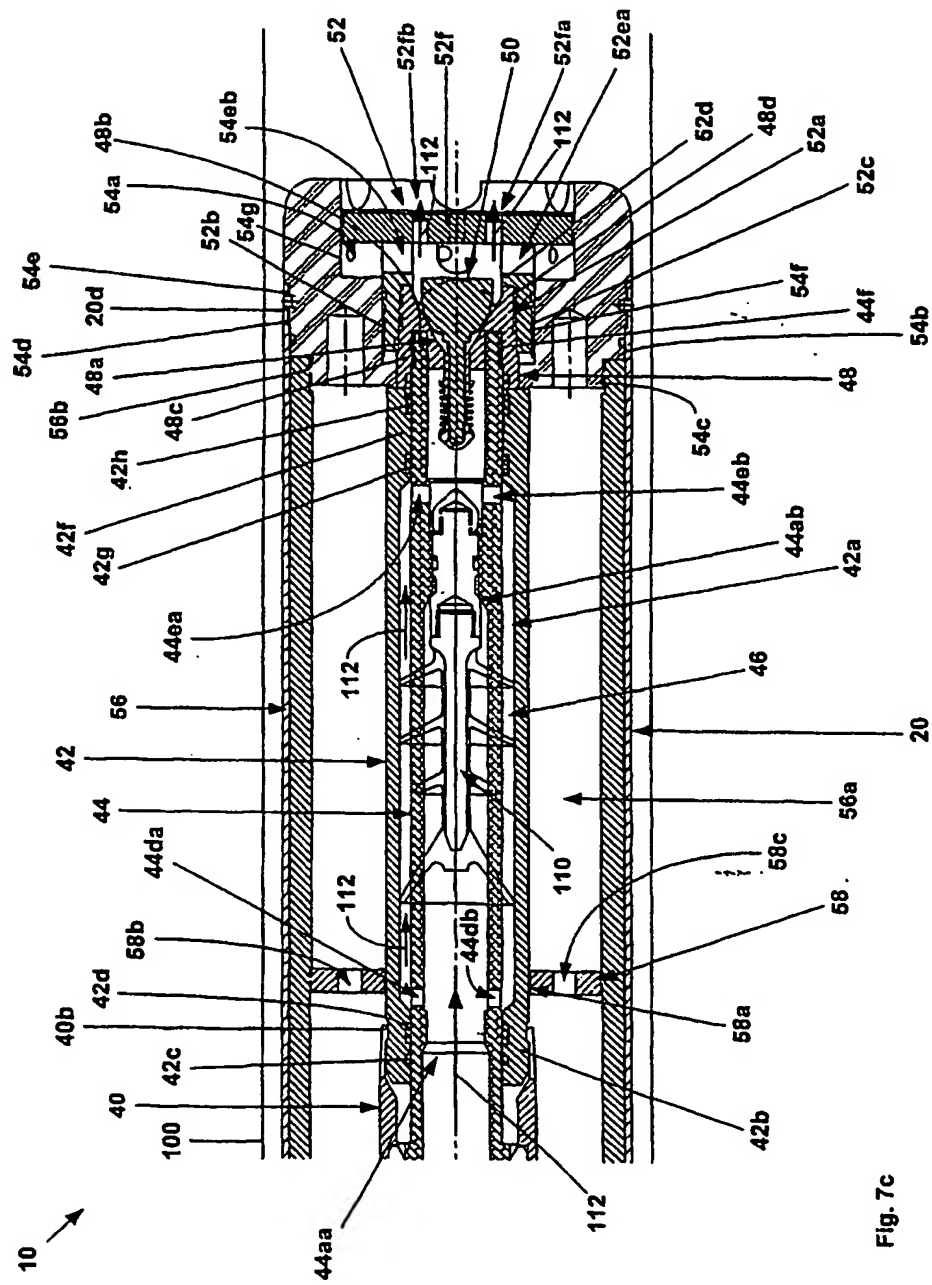
104a
112
104
12
12c
12b
22a
22
12d
14b
18b
100
20a
20
16b
18a
20b
16d
24
14a
18e
24b
18c
24a
16c
18d
16h
16j
16i
112
16
14
16a
26a
26
16g
14d
14g
44a
44
14h
26c
14c
26b
16e

Fig. 7a



58b
42e
40b
38a 14f
14e
38c
16f
14d
14g
36
20
16
44c
32
28
30a
10
42c
42d
42b
42
58
56
58c
40
112
44a
40a
38
100
14j
34
38b
14h
30

Fig. 7b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54g
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54e
20d
54d
48a
56b
48c
42h
42f
42g
62d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
44ea
112
56
42
44
44da
112
58b
42d
40b
42c
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44aa
112
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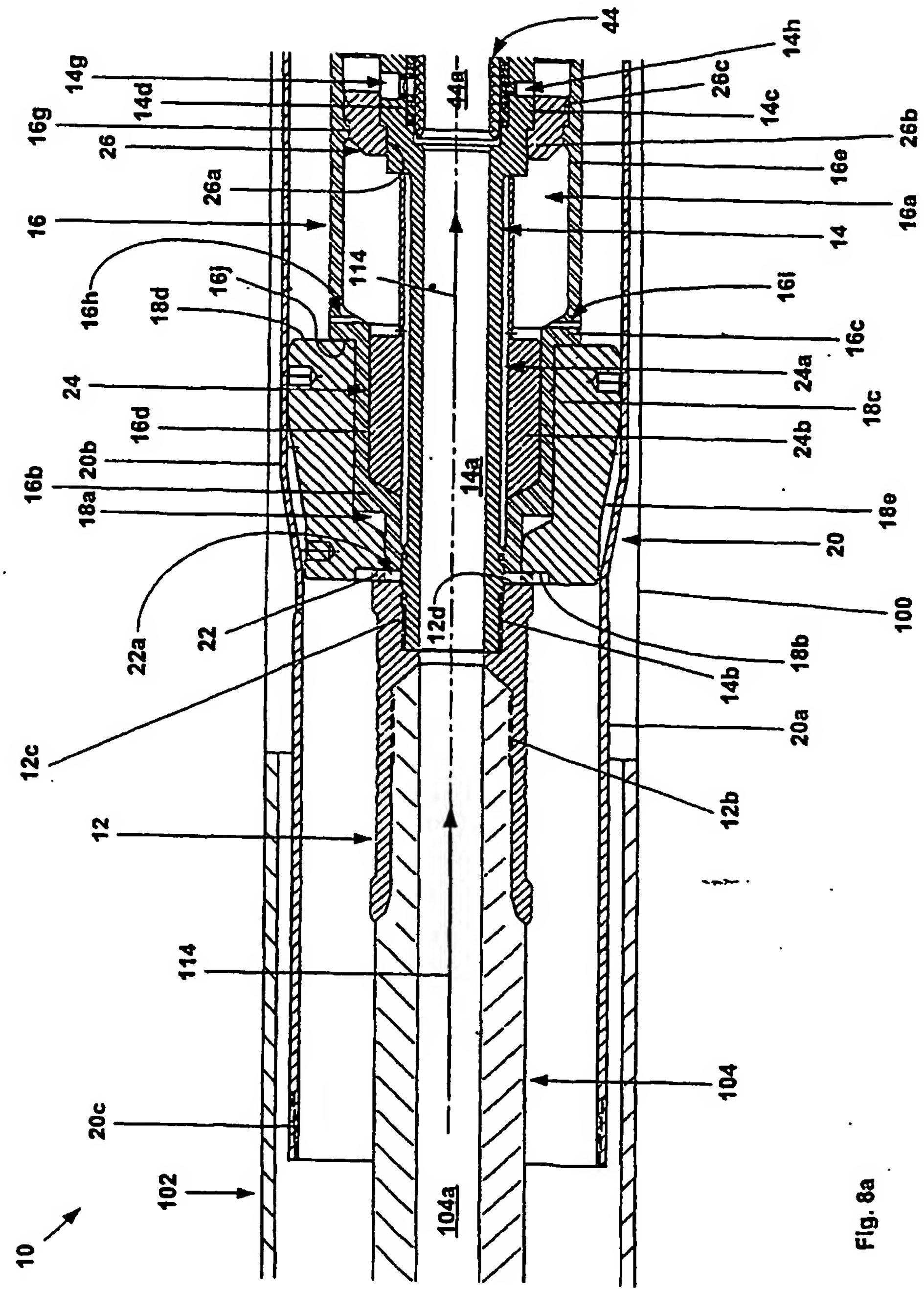
46
20
56a
110
58c
58
44db
58a
42b

Fig. 7c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16b
20b
16d
24
18d
16h
16j
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16
26a
26
16g
14d
14g
44
44a
14a
104a
12d
14h
26c
14c
26b
16e
16a
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16i
16c
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18c
24b
18e
20
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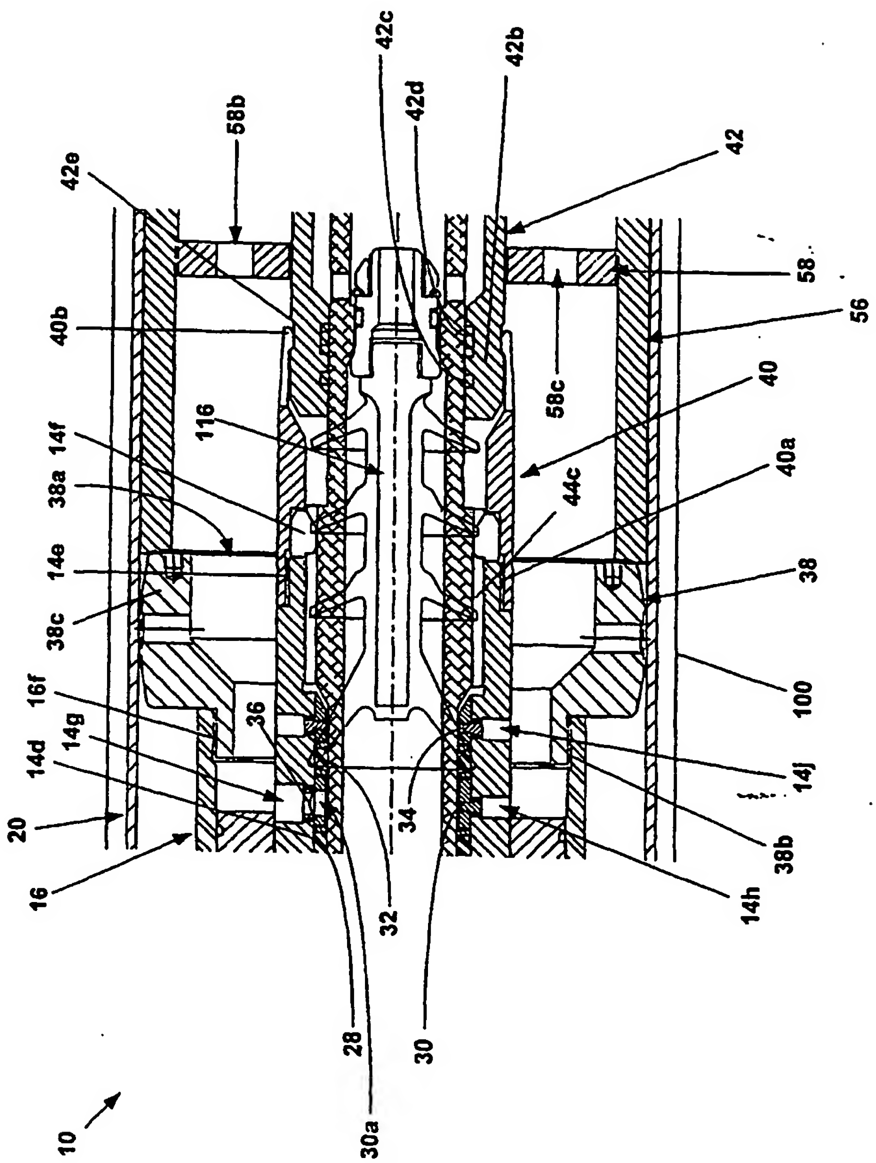
18b
14b
20a
12b
104

Fig. 8a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14g
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38c
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58b
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30a
32
30
34
42c
42d
42b
42
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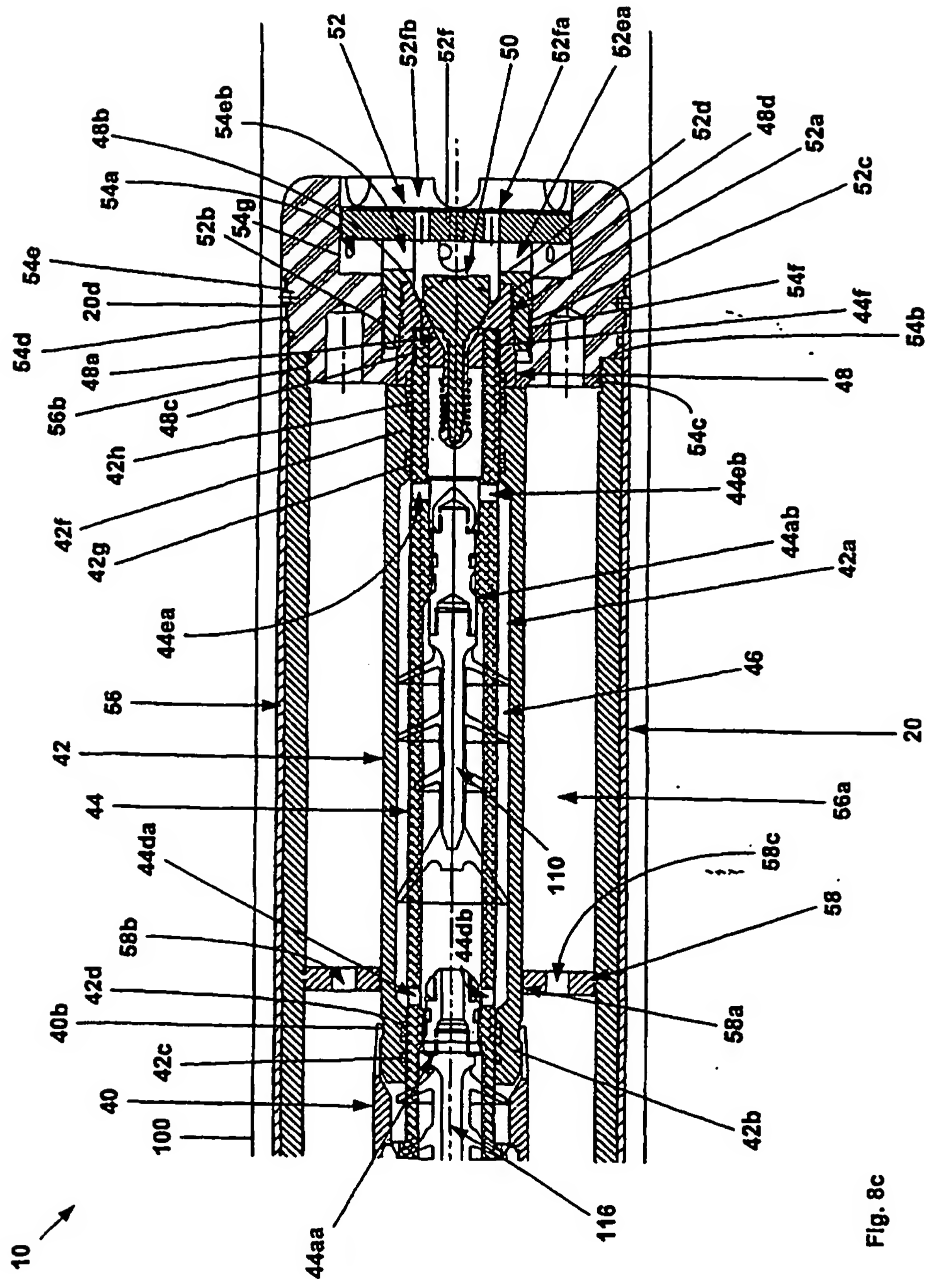
56
58c
40
40a
44c
38
100
14j
38b
14h

Fig. 8b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56b
48c
42h
42f
42g
44ea
56
42
44
44da
58b
42d
40b
42c
40
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44aa
116
110
44db
52d
48d
52a
52c
54f
44f
54b
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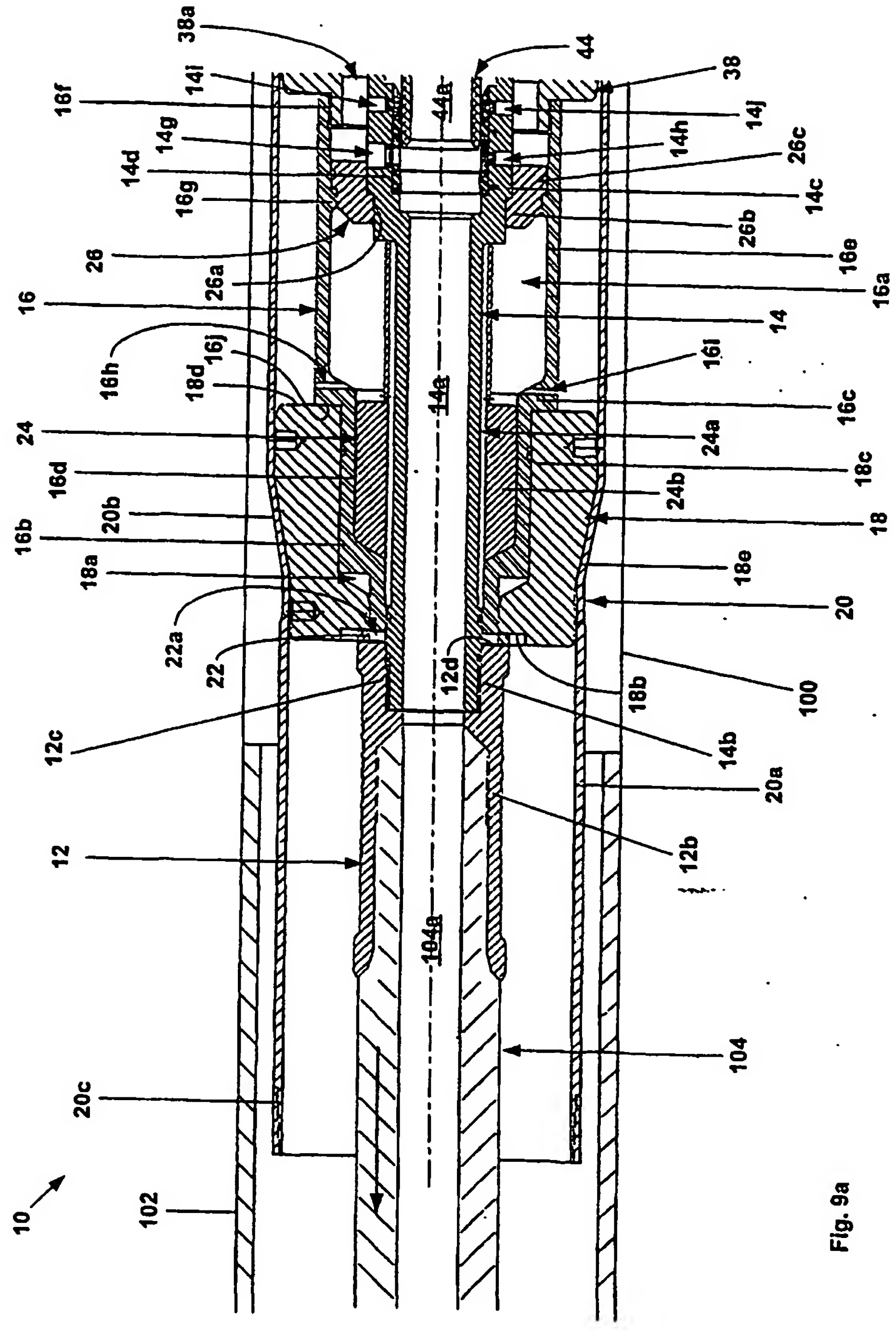
54c
44eb
44ab
42a
46
20
56a
58c
58
58a
42b

Fig. 8c



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14g
14h
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26c
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26b
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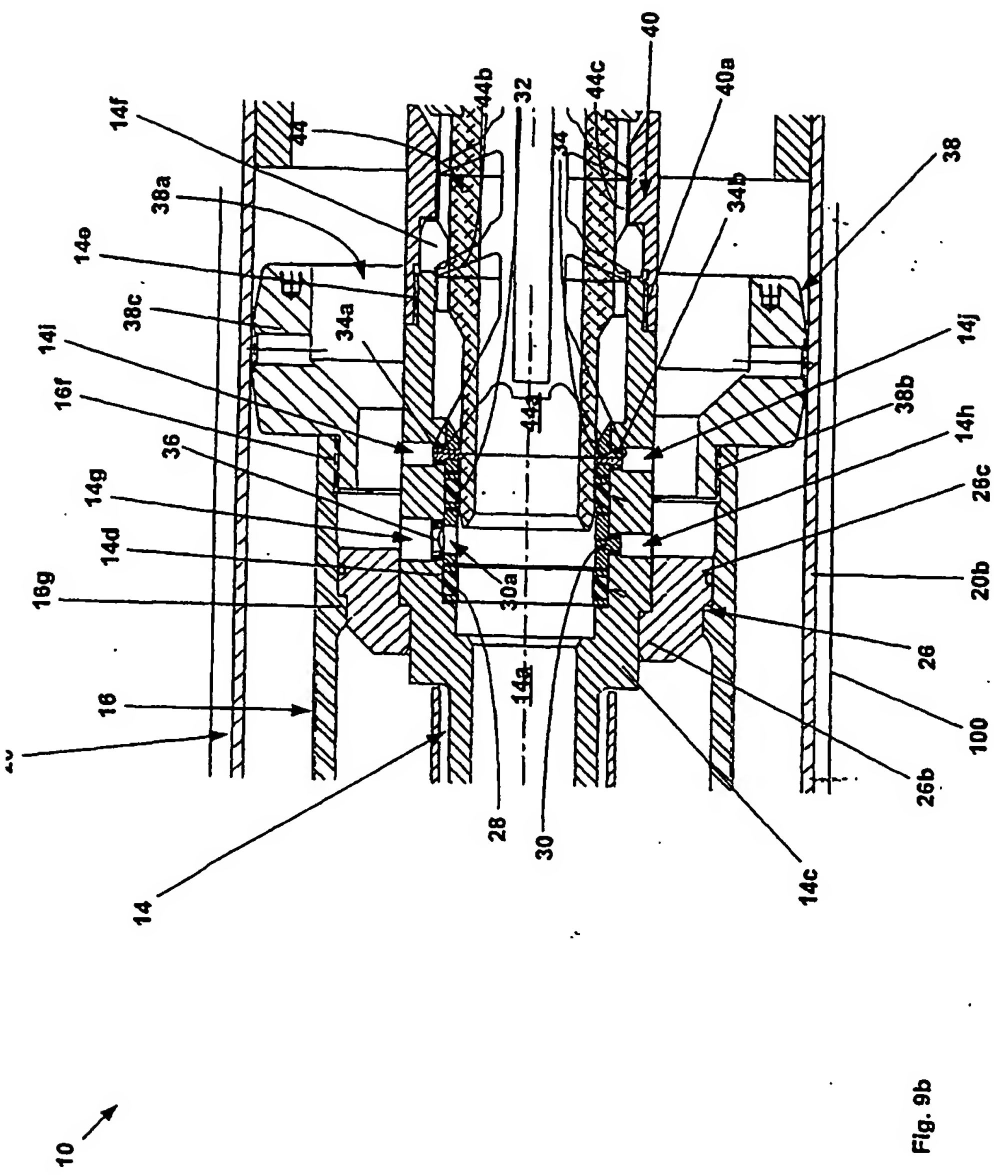
26a
16a
16
14
16h
16j
18d
16i
14a
16c
24
24a
16d
18c
24b
20b
18
16b
18e
18a
20
22a
22
12d
18b
100
12c
14b
20a
12
12b
104a
104
20c
10
102

Fig. 9a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16f
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14e
38a
14f
34a
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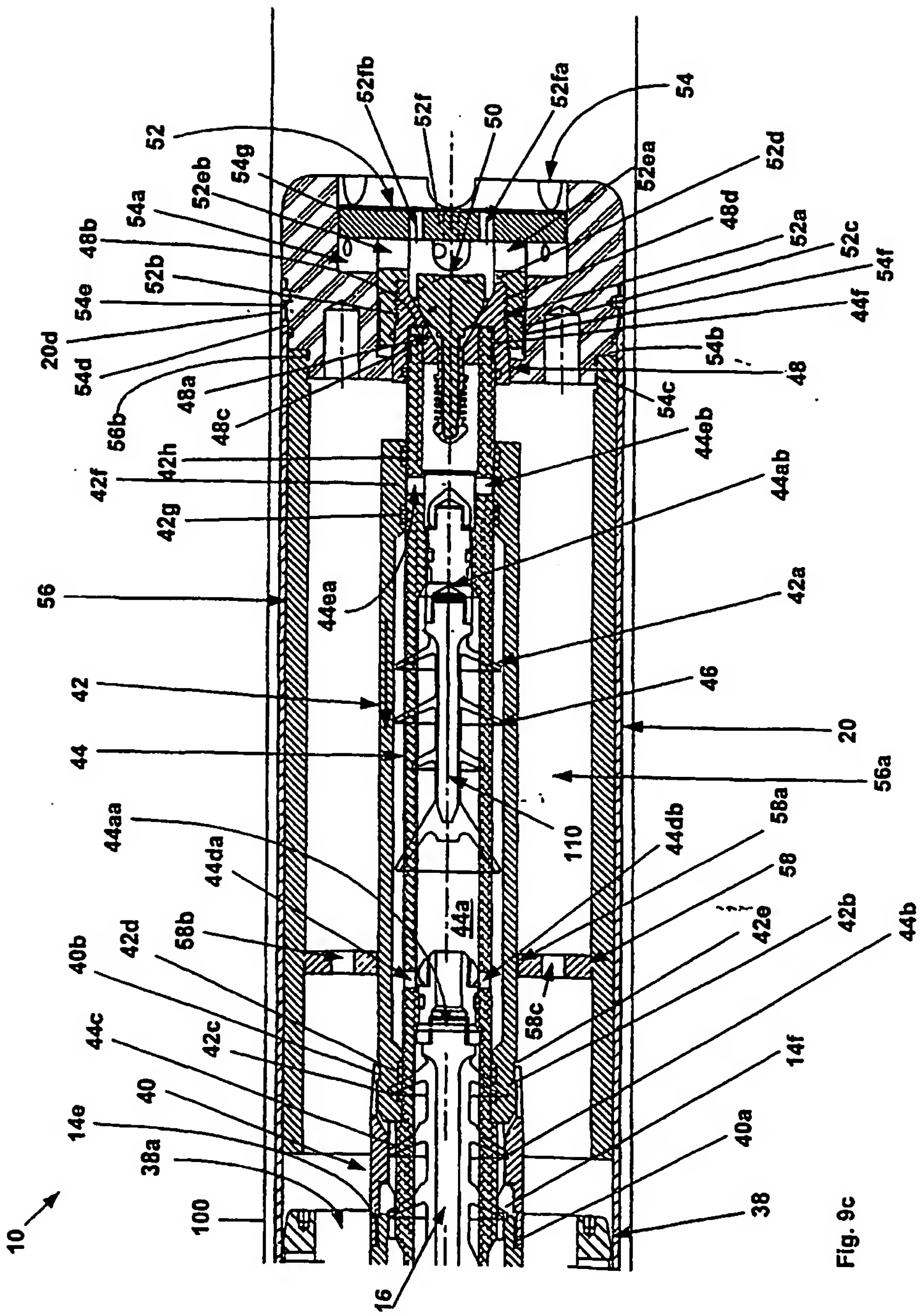
44b
32
34
44c
40
40a
34b
38
14j
38b
14h
26c
20b
26
100
26b
14c
30
30a
28
14a
44a

Fig. 9b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42c
40b
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58b
44da
44aa
44
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44ea
42g
42f
42h
58b
48c
48a
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
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52fa
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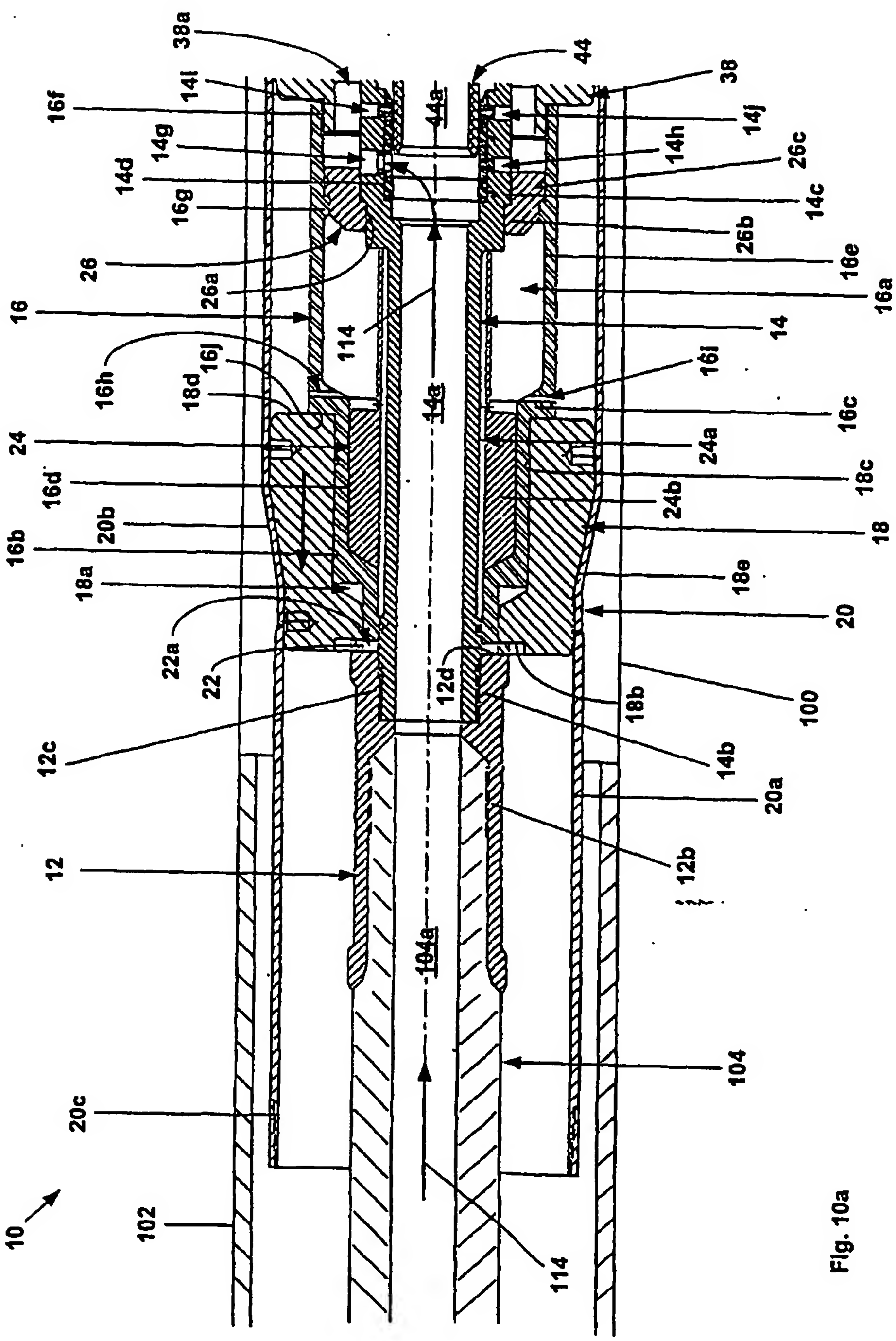
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
46
20
56a
110
44db
58a
58
42e
42b
44b
14f
40a
38
58c
44a

Fig. 9c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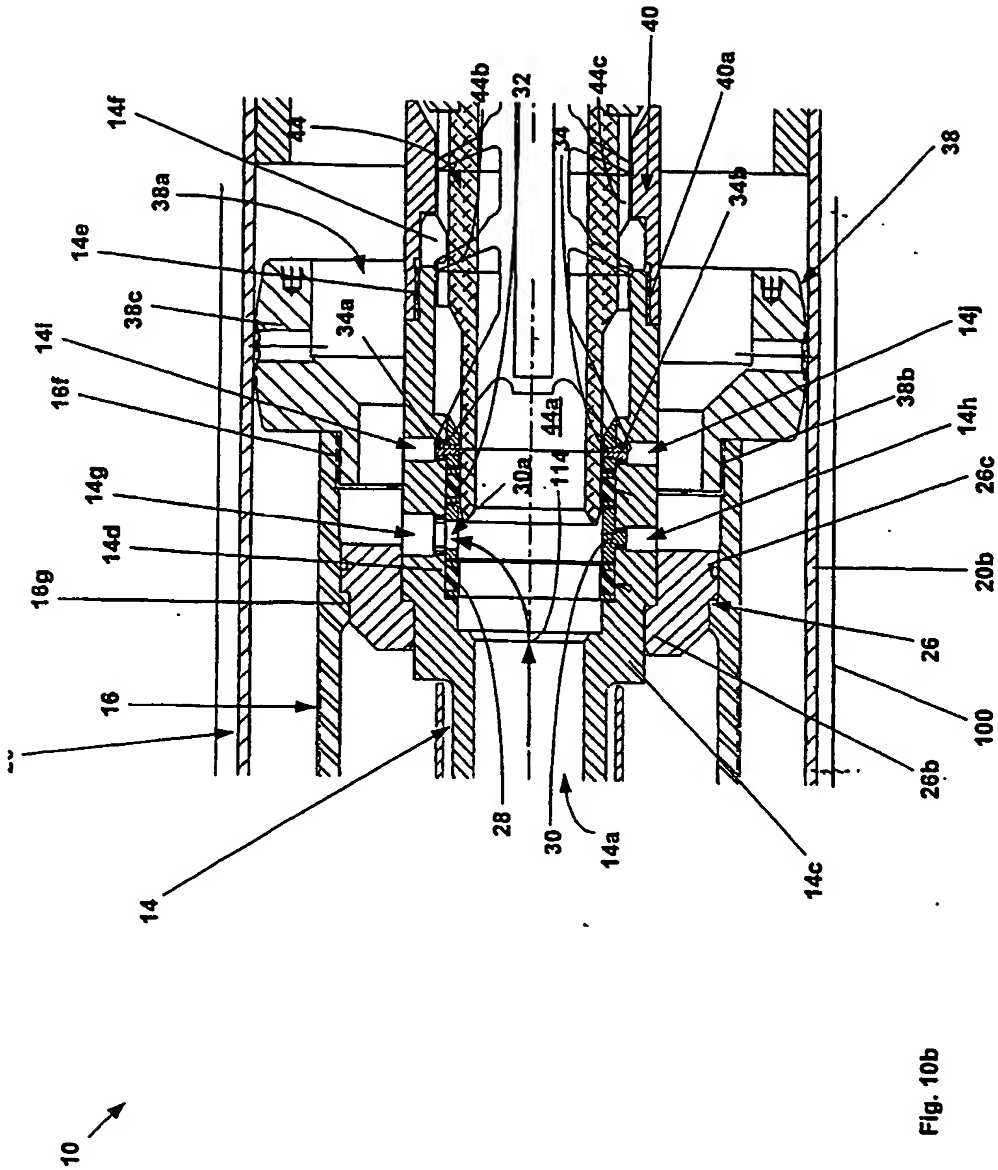
12b
12c
22
22a
12d
14b
18b
100
20a
18a
16b
20b
16d
24
18d
16j
16h
16
26
26a
114
14a
16g
14d
14g
16f
14i
38a
44
44a
38
14j
14h
26c
14c
26b
16e
16a
14
16i
16c
24a
18c
24b
18
18e
20

Fig. 10a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34b
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38c
34a
14l
16f
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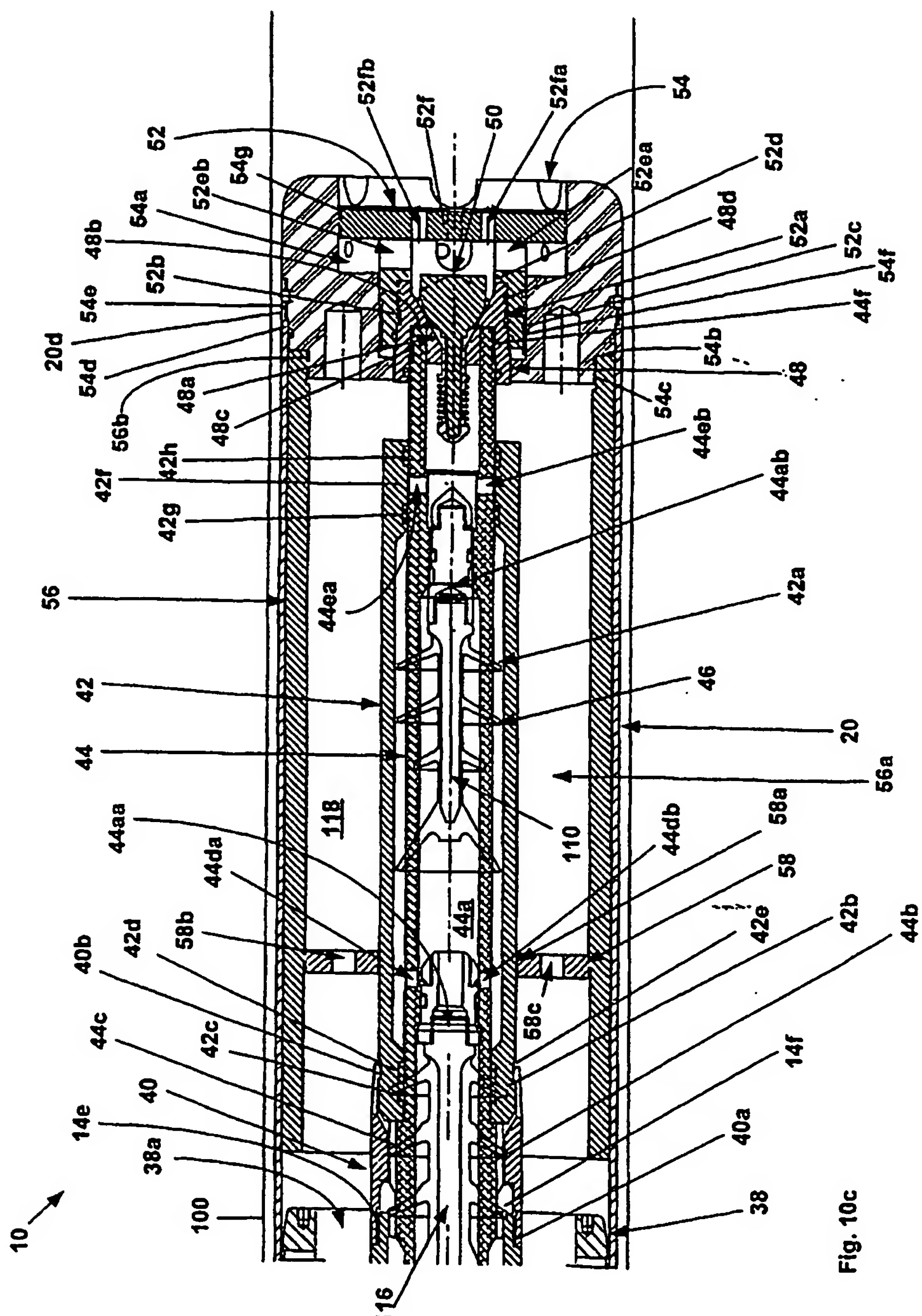
14j
38b
30a
114
14h
14g
26c
14d
20b
16g
26
16
100
26b
28
30
14a
14
14c
10

Fig. 10b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14e
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44c
40b
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42d
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44
42
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42g
42f
42h
44ea
48c
56b
48a
54d
20d
54e
52b
48b
54a
52eb
54g
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52fb
52f
50
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54c
44eb
44ab
42a
46
20
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44db
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42b
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58c
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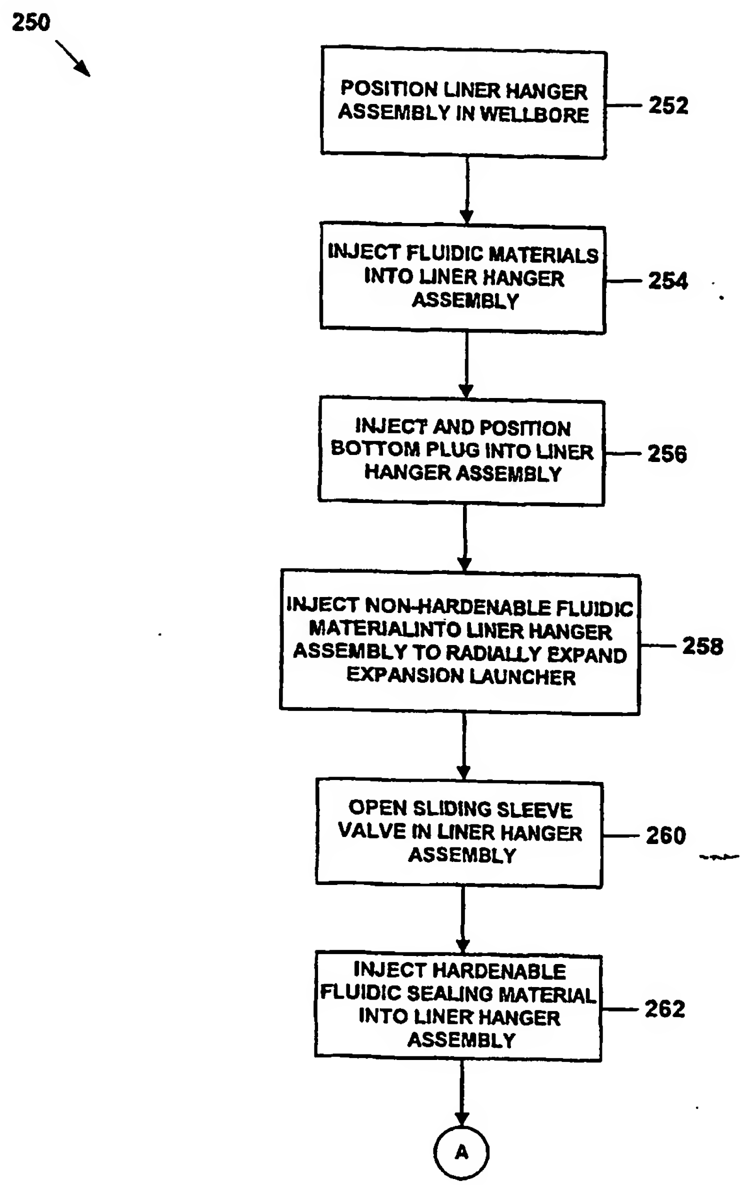
38
116

Fig. 10c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POSITION LINER HANGER ASSEMBLY IN WELLBORE
252
INJECT FLUIDIC MATERIALS INTO LINER HANGER ASSEMBLY
254
INJECT AND POSITION BOTTOM PLUG INTO LINER HANGER ASSEMBLY
256
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
258
OPEN SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
260
INJECT HARDENABLE FLUIDIC SEALING MATERIAL INTO LINER HANGER ASSEMBLY
262
A

Fig. 11a

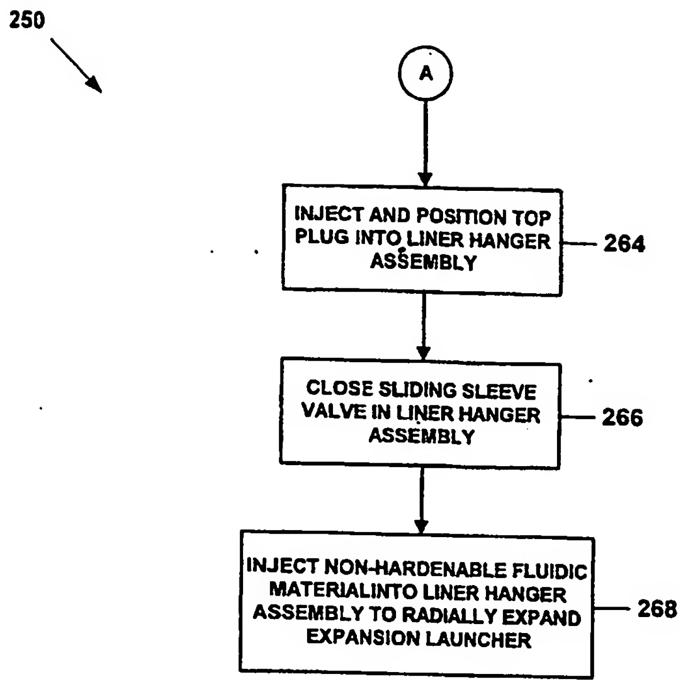
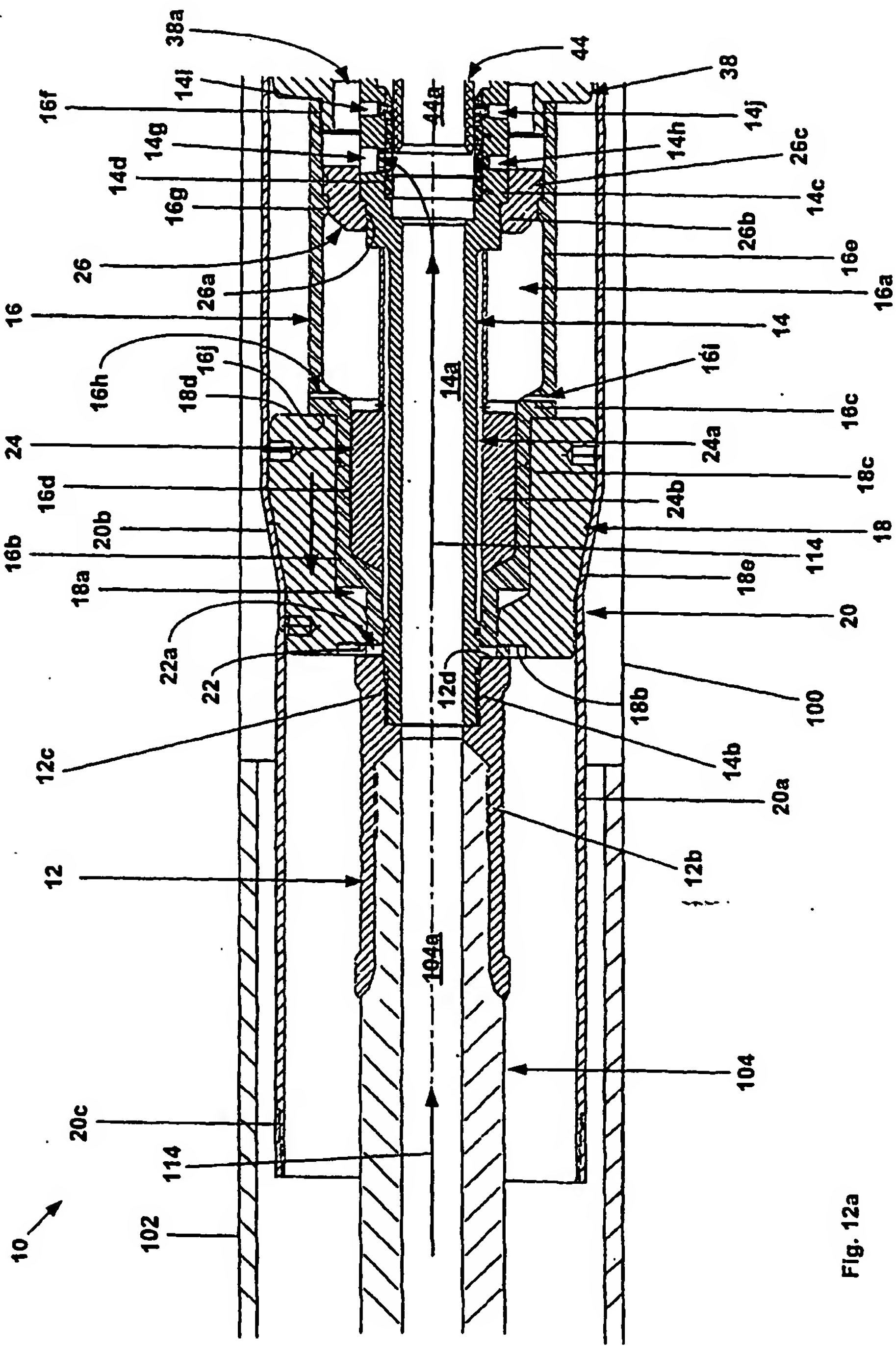

250
A
INJECT AND POSITION TOP PLUG INTO LINER HANGER ASSEMBLY
264
CLOSE SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
266
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
268

Fig. 11b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16j
16i
18d
14a
16c
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24a
18c
16d
24b
20b
18
16b
114
18a
18e
20
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12c
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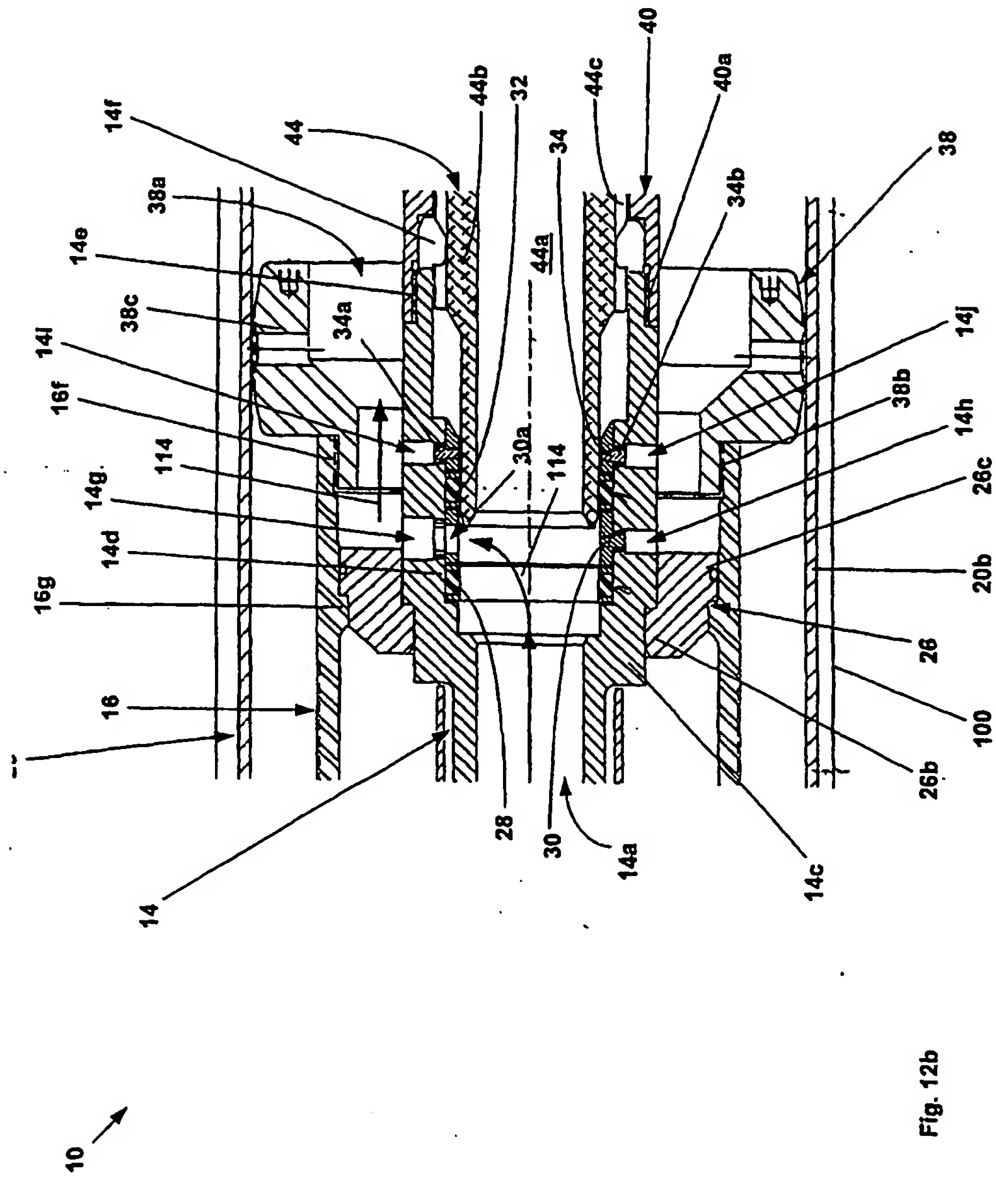
20a
12
12b
104a
104
20c
114
10
102

Fig. 12a



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14j
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16f
16g
20b
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26b
26c
28
30
30a
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34b
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38b
38c
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40a
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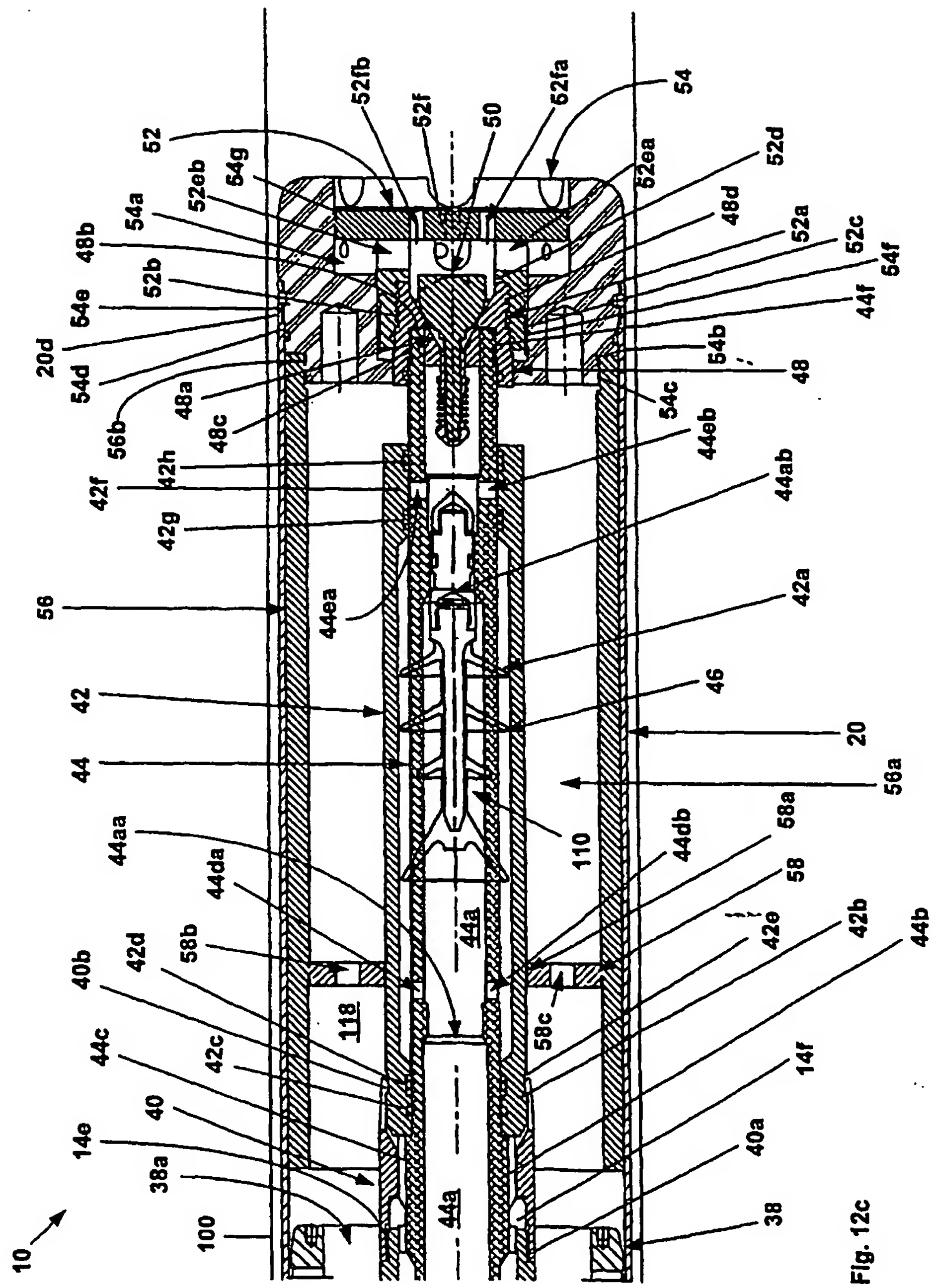
44a
44b
44c
100
114

Fig. 12b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40b
42d
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44da
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42
56
44ea
42g
42f
42h
56b
48c
48a
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
50
52fa
54
52ea
52d
48d
52a
52c
54f
44f
54b
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54c
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44ab
42a
46
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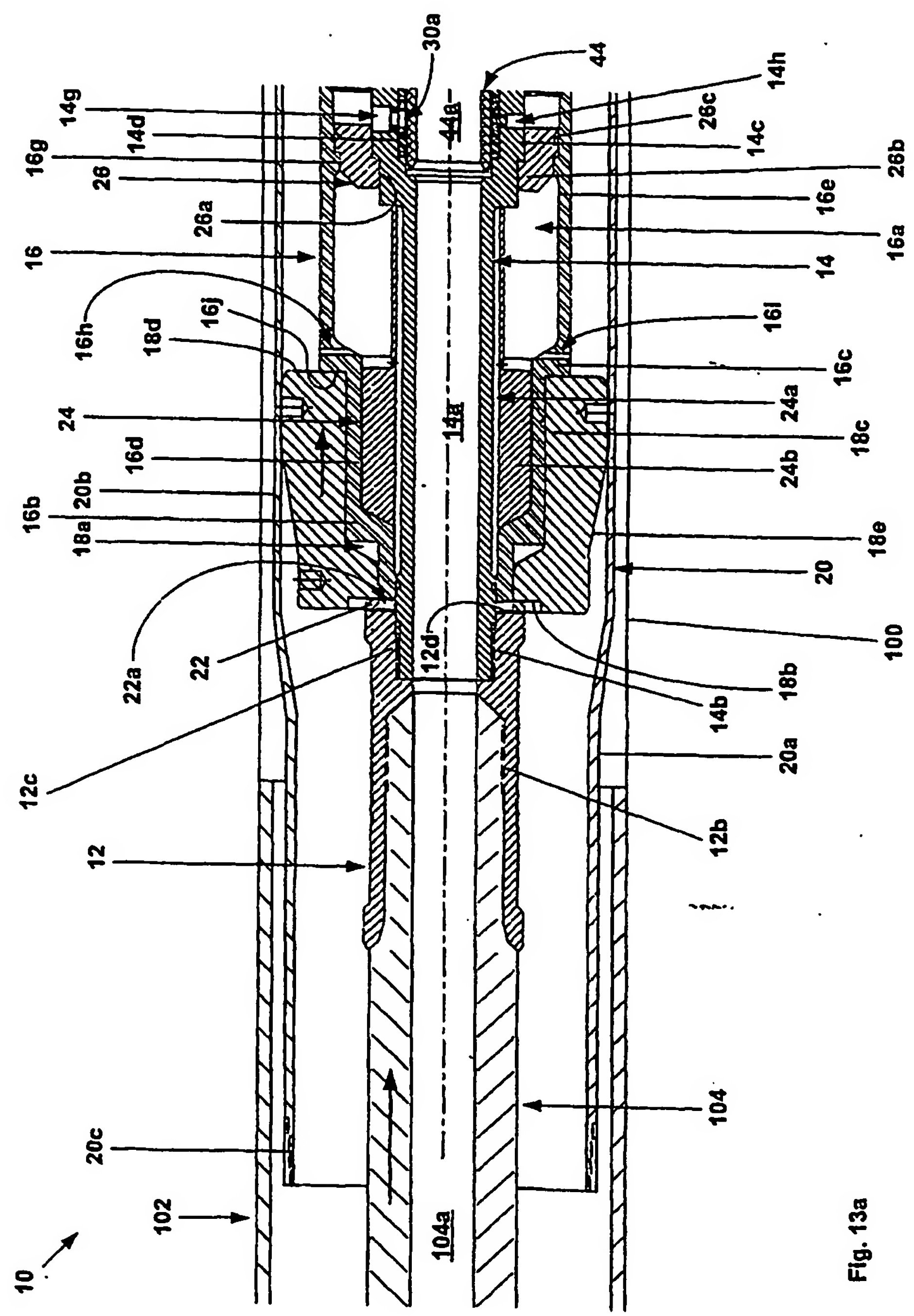
42b
44b
58c
118
44a
14f
40a
38

Fig. 12c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16g
26b
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26a
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16
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18d
16c
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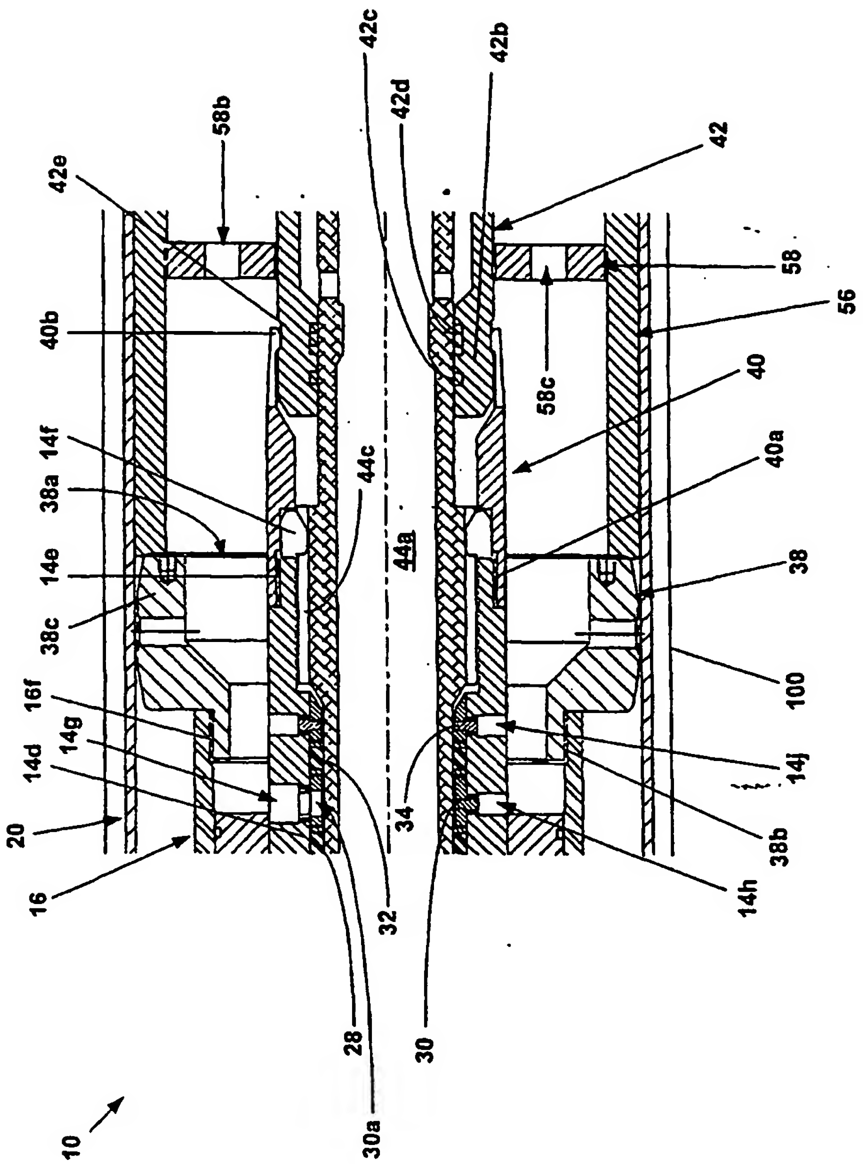
18c
16d
24b
20b
16b
18a
18e
20
22a
22
12d
100
18b
14b
12c
20a
12b
12
104
20c
102
104a
10
Fig. 13a



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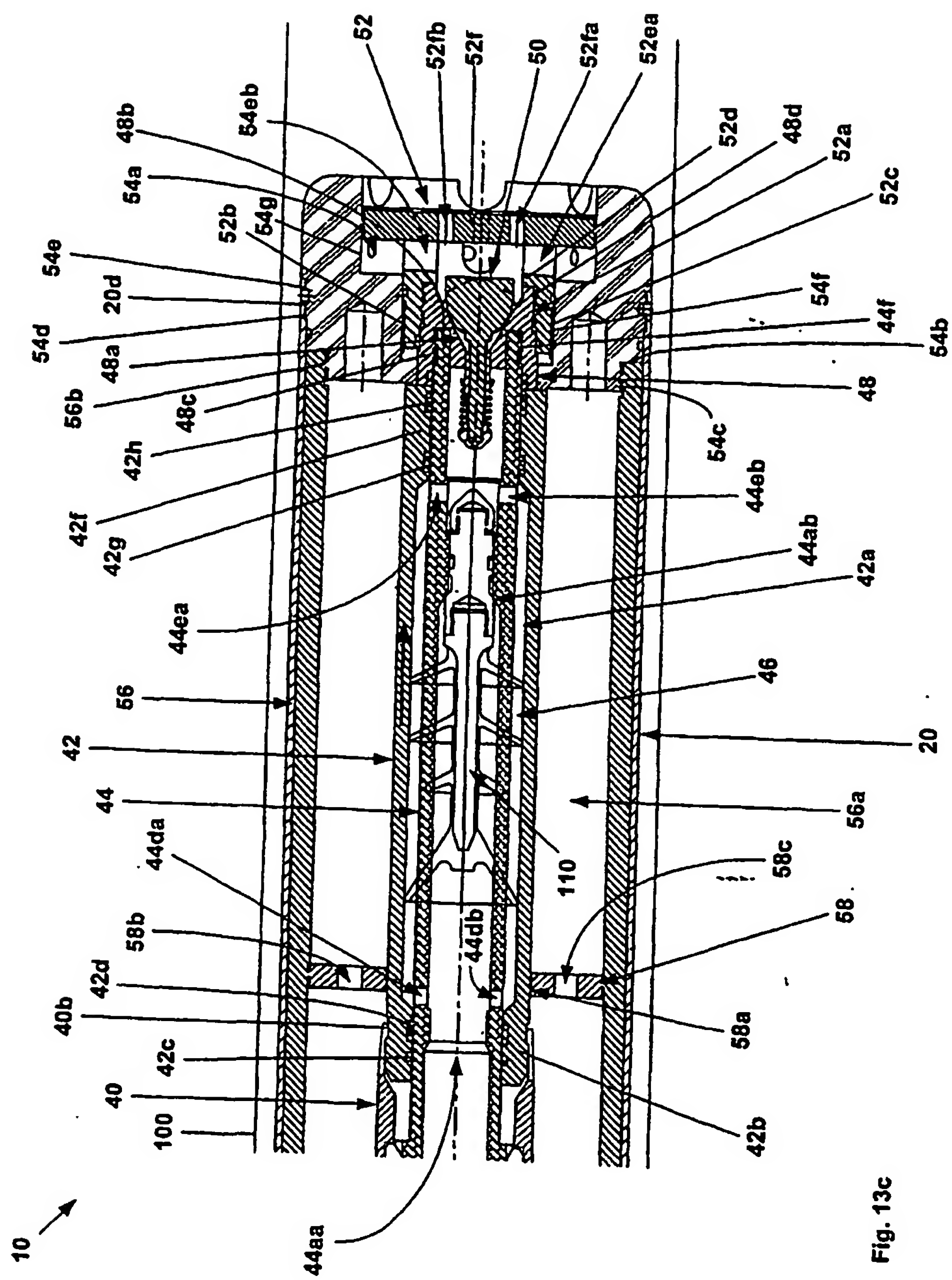
16
20
14d
14g
16f
38c
14e
38a
14f
40b
42e
58b
28
30a
32
44c
44a
30
34
42c
42d
42b
42
40
40a
58c
58
56
38
100
14j
38b
14h

Fig. 13b



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100
40
42c
40b
42d
58b
44da
44
42
56
44ea
42g
42f
42h
48c
56b
48a
54d
20d
54e
52b
54g
54a
48b
54eb
52
52fb
52f
50
52fa
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
46
20
56a
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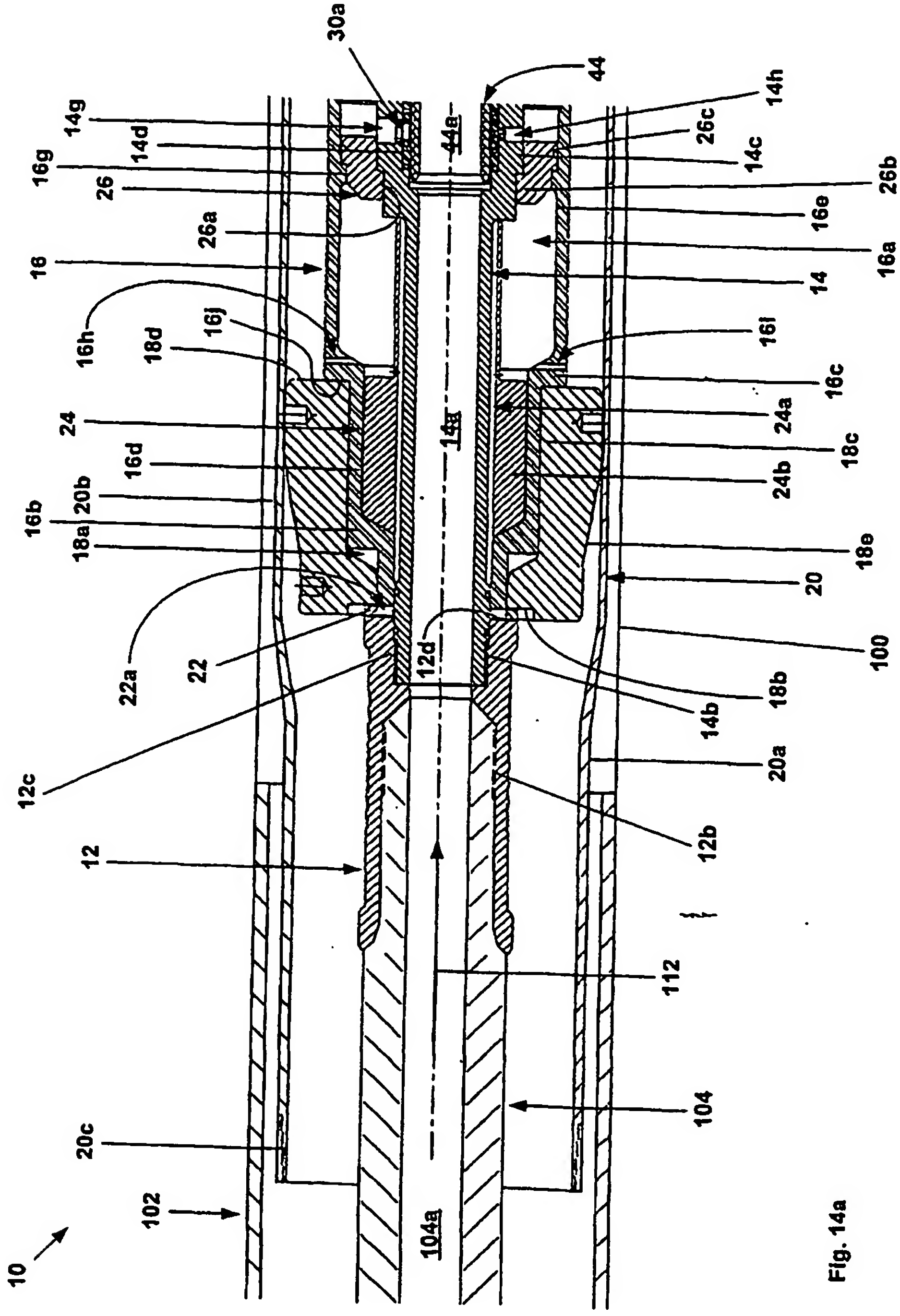
58c
58
44db
58a
42b
44aa

Fig. 13c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14c
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26b
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16e
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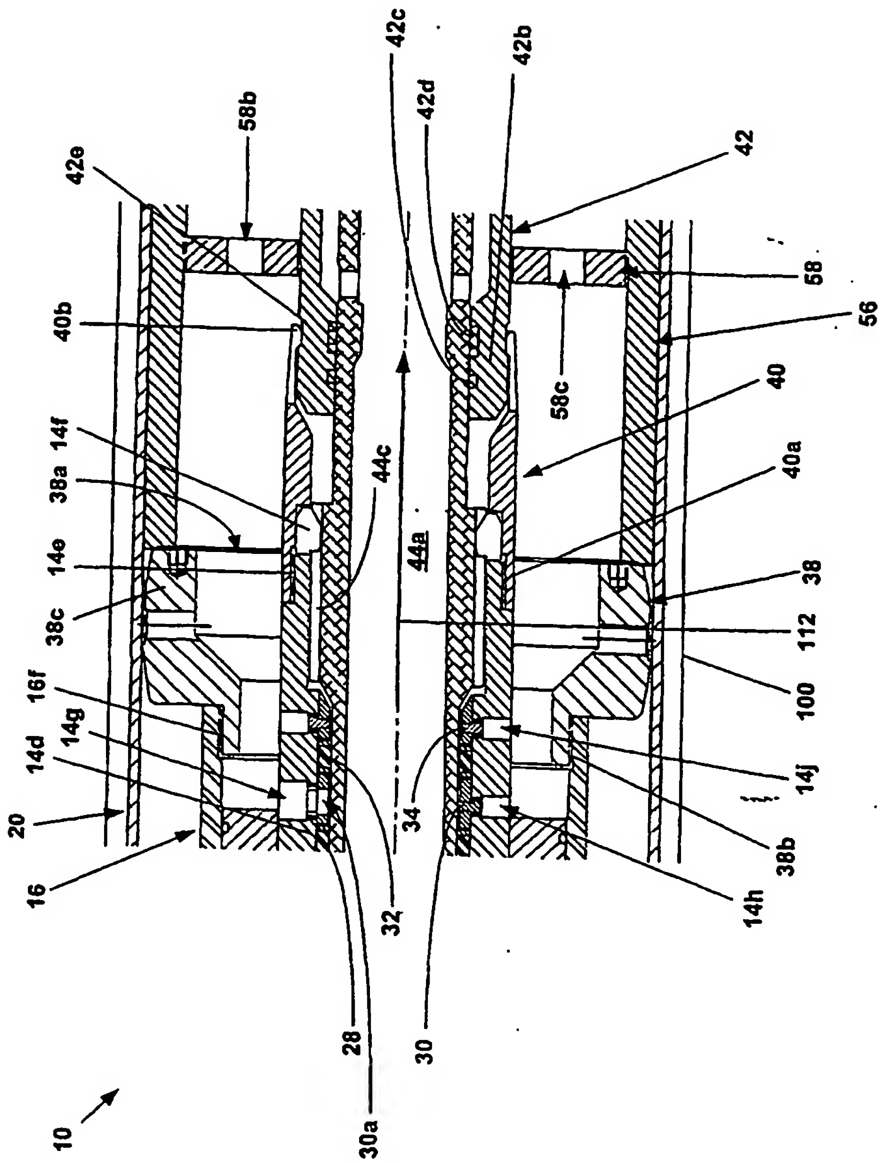
16a
14
16h
16j
16i
18d
16c
24
14a
24a
18c
16d
24b
20b
16b
18a
18e
20
22a
12d
100
22
18b
14b
12c
20a
12
12b
112
104
20c
102
104a
10

Fig. 14a



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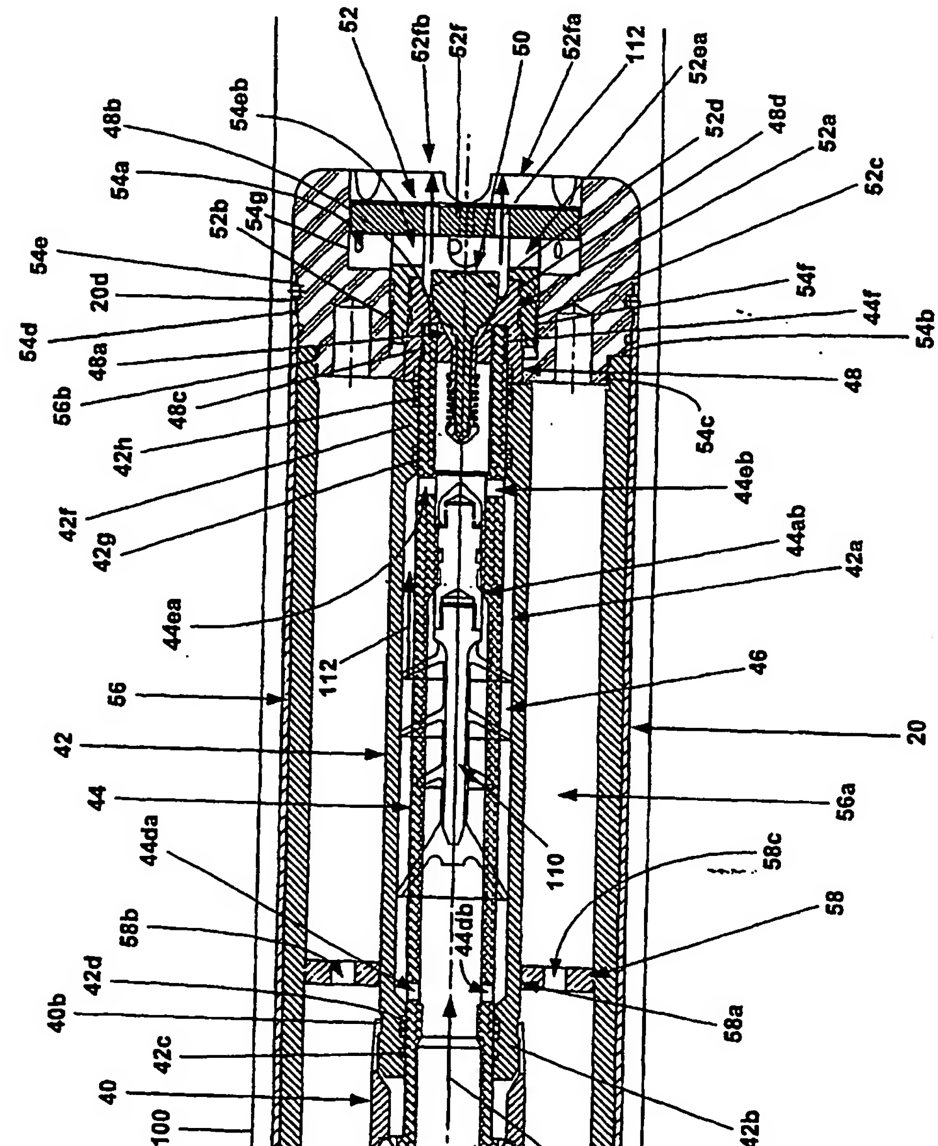
14d
14g
16f
38c
14e
38a
14f
40b
42e
58b
28
30a
32
44c
44a
30
34
42c
42d
42b
40
58c
42
58
56
40a
38
112
100
14j
38b
14h

Fig. 14b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56
44ea
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42f
42h
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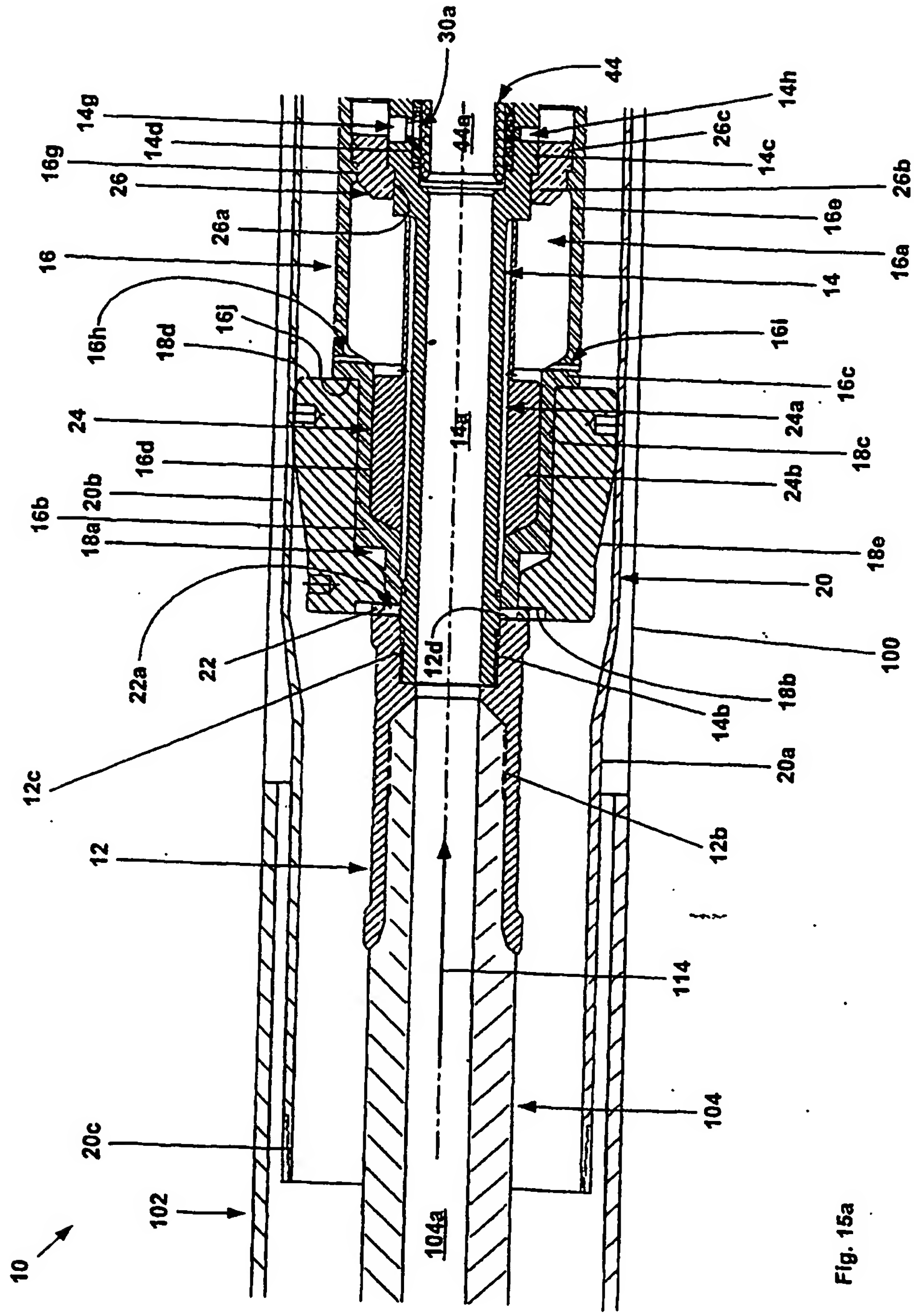
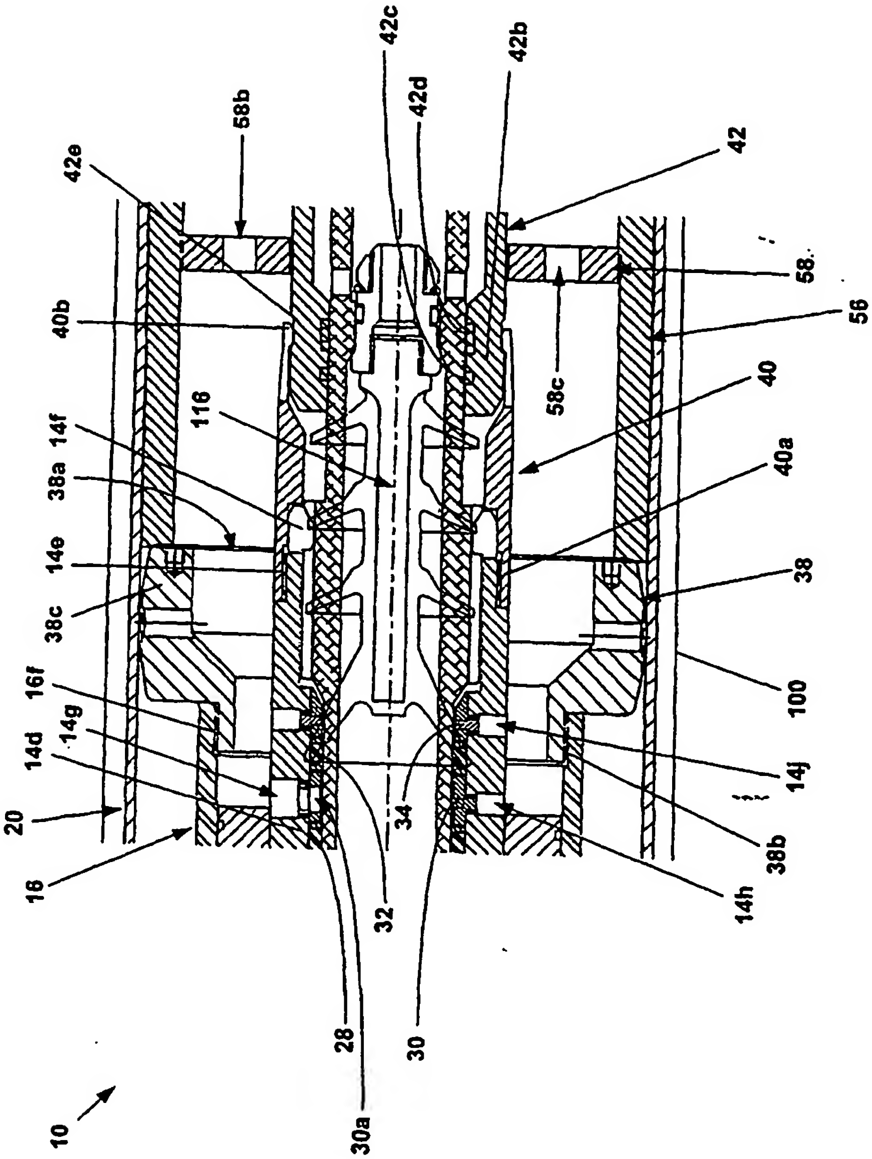
56b
48a
54d
20d
54e
52b
54g
54a
48b
54eb
52
52fb
52f
50
52fa
112
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
112
46
20
56a
110
58c
58
44db
58a
42b
112

Fig. 14c



10
102
20c
104a
12
12c
22a
22
18a
16b
20b
16d
24
18d
16h
16j
16
26a
26
16g
14d
14g
30a
44
44a
14a
12d
14h
26c
14c
26b
16e
16a
14
16i
16c
24a
18c
24b
18e
20
100
18b
14b
20a
12b
114
104

Fig. 15a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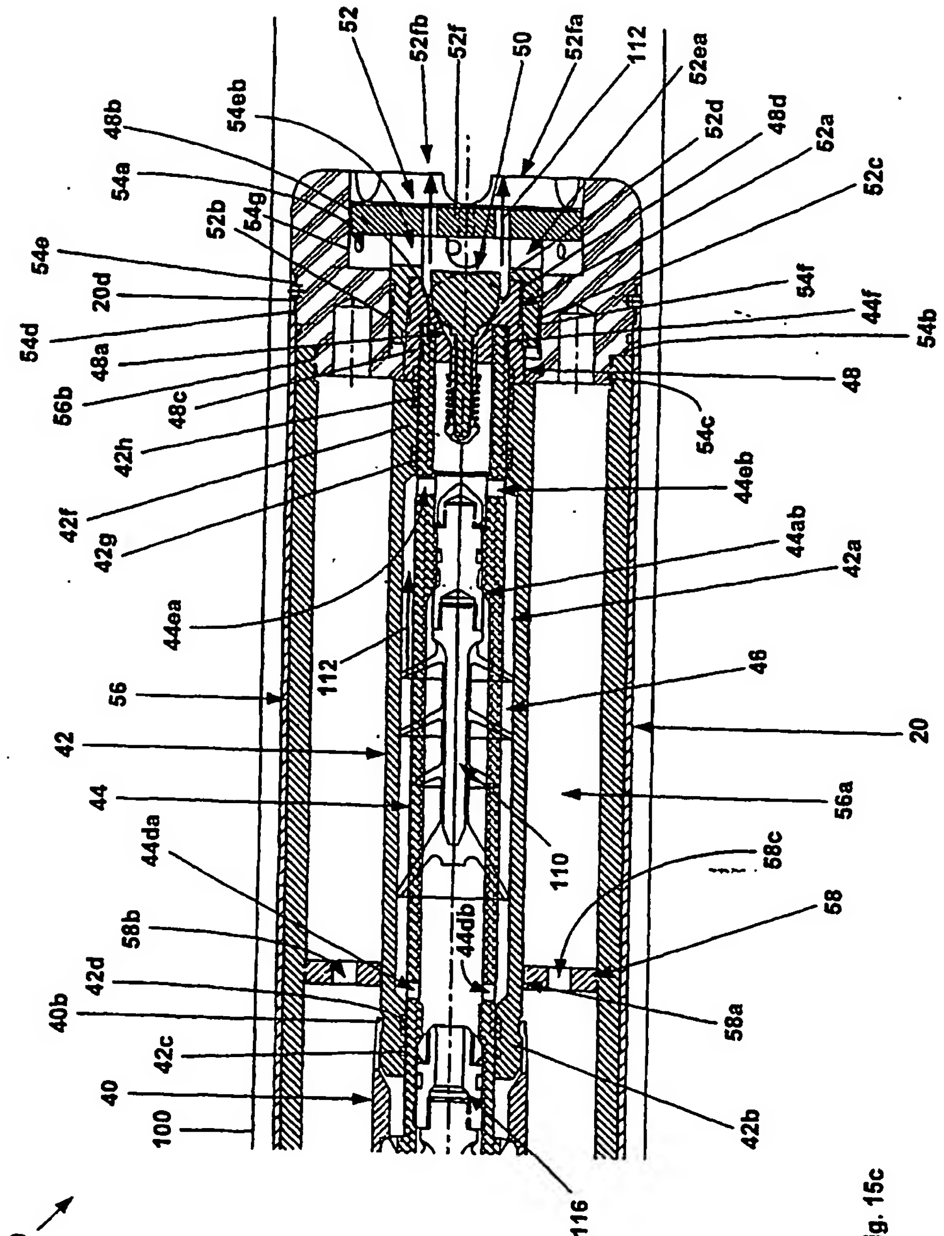
58b
42c
42d
42b
42
58
56
40b
58c
40
116
14f
38a
40a
14e
38
38c
100
16f
14g
14d
14j
20
34
38b
16
32
14h
28
30
30a
10

Fig. 15b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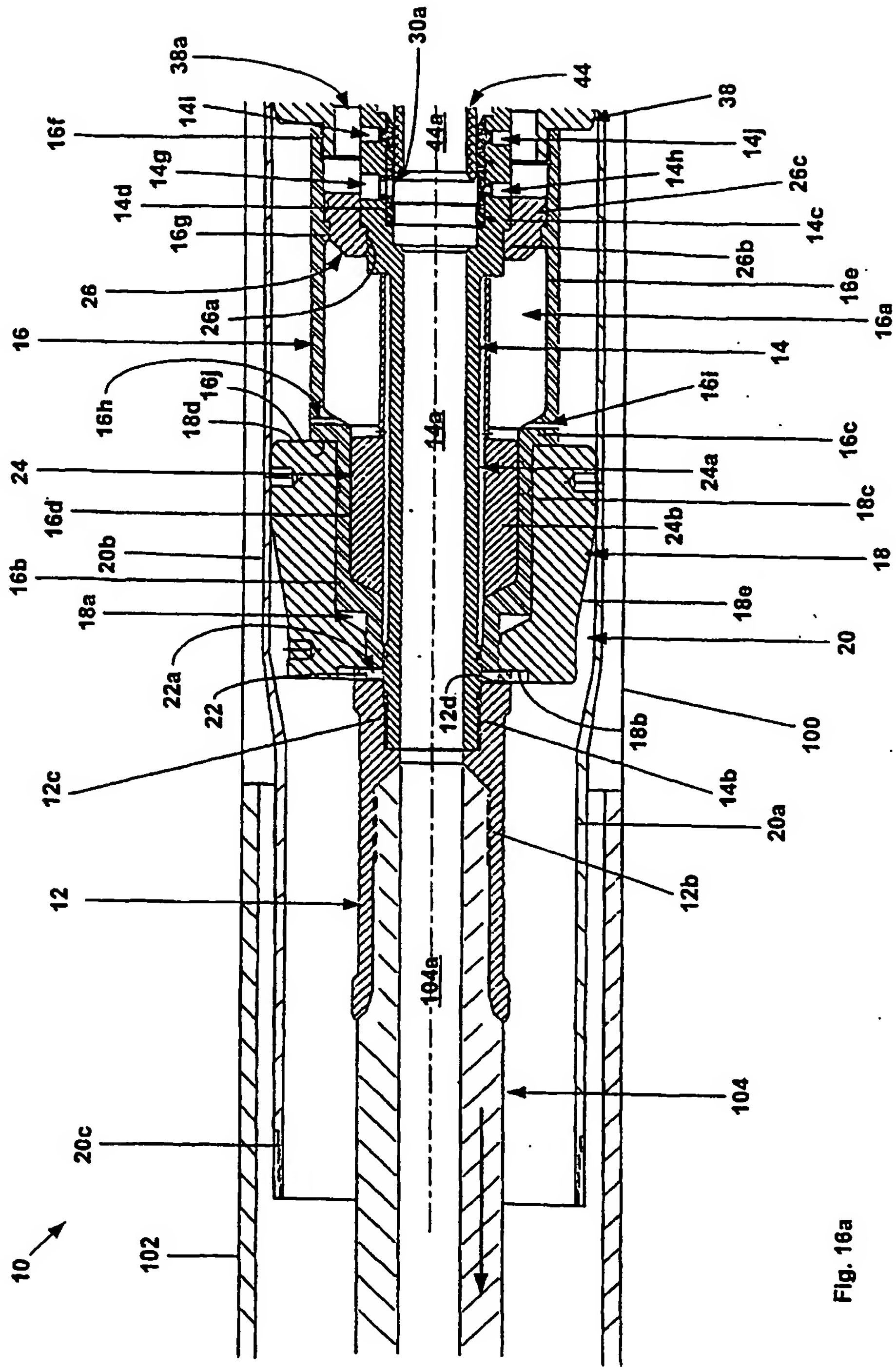
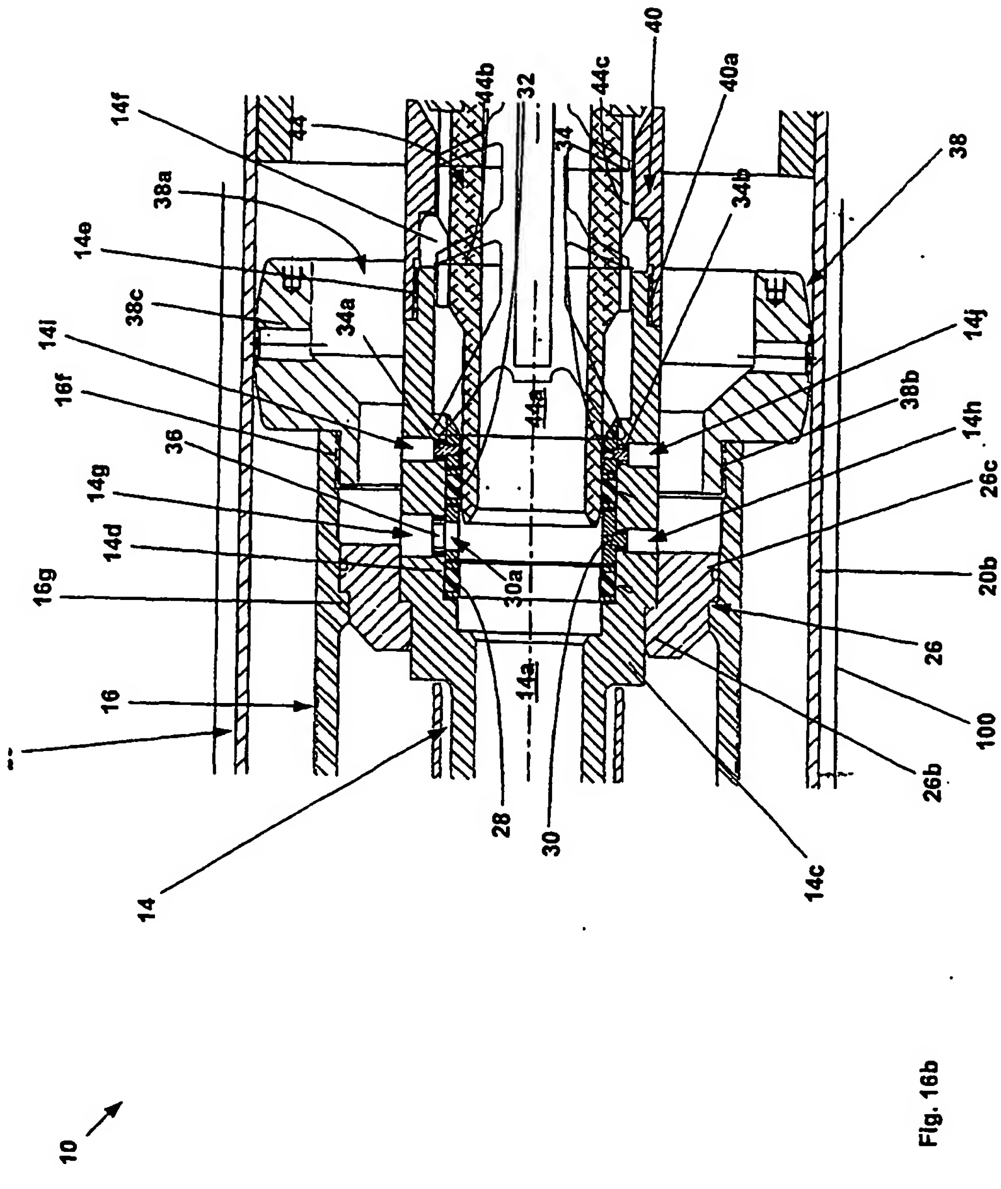
42c
40b
42d
58b
44da
44
42
56
44ea
42g
42f
42h
56b
48c
48a
54d
20d
54e
52b
54g
54a
48b
54eb
52
52fb
52f
50
52fa
112
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
42a
112
46
20
56a
110
58c
58
44db
58a
42b
116

Fig. 15c



38a
30a
44
38
14l
14j
16f
14g
14h
26c
14d
14c
16g
26b
16e
26
26a
16a
16
14
16h
16j
16i
18d
14a
16c
24
24a
16d
18c
24b
20b
18
16b
18e
18a
20
22a
22
12d
18b
100
12c
14b
20a
12
12b
104a
104
20c
10
102

Fig. 16a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16g
14d
14g
36
16f
14i
38c
14e
38a
14f
44
44b
32
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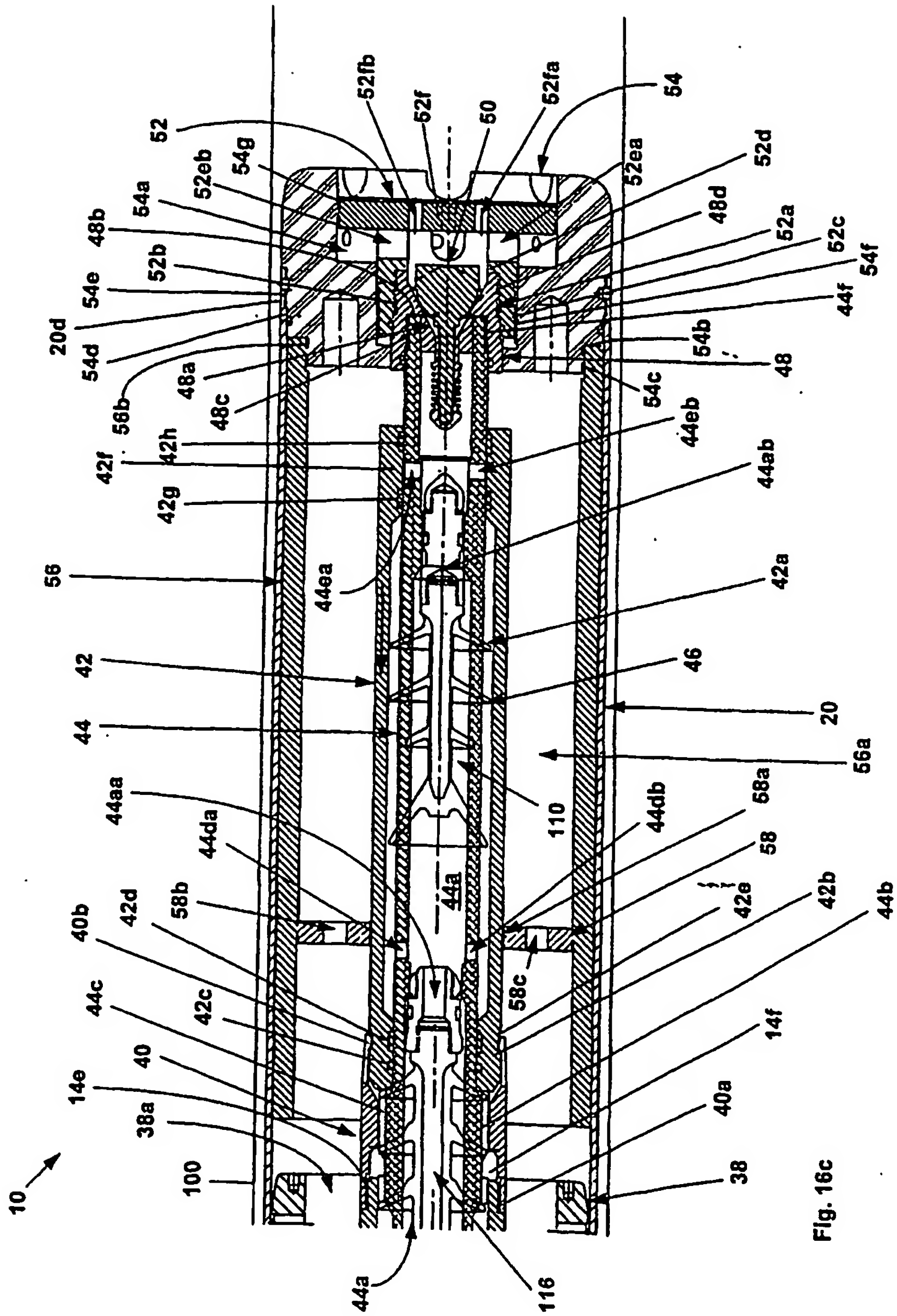
44c
40
40a
34b
38
34a
14a
14j
38b
14h
26c
20b
26
100
26b
14c
30
28
30a
14a

Fig. 16b



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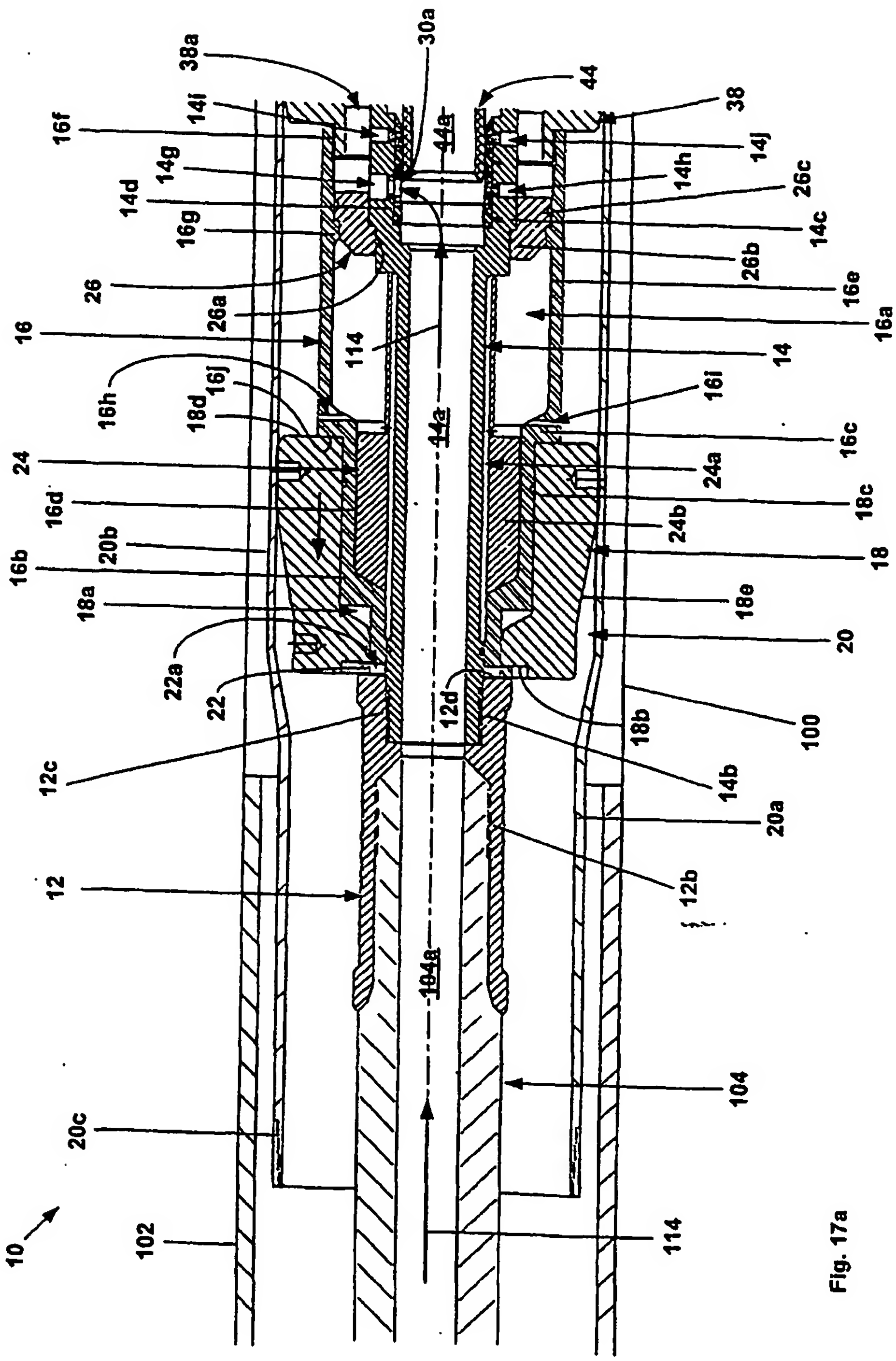
100
38a
14e
40
44c
40b
42d
58b
42c
44da
44aa
44
42
56
42g
42f
42h
56b
48c
48a
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
50
52fa
54
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
44ea
42a
46
20
56a
110
44a
44db
58a
58
58c
42e
42b
44b
14f
40a
38
44a
116

Fig. 16c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12c
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22a
18a
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20b
16d
24
18d
16j
16h
16
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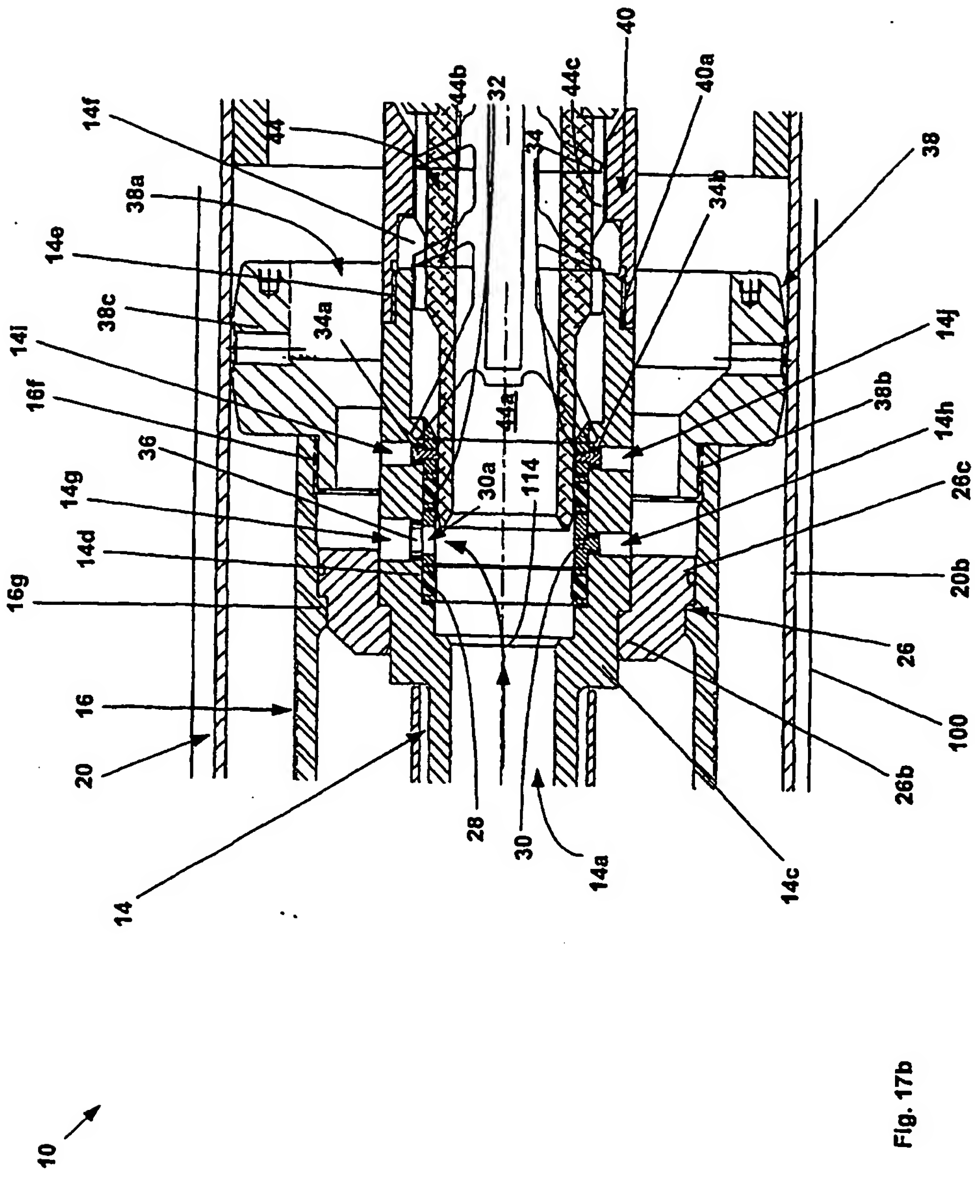
26
16g
14d
14g
16f
14i
38a
30a
44a
44
38
14j
14h
26c
14c
26b
16e
16a
14
114
14a
16i
16c
24a
18c
24b
18
18e
20
18b
12d
100
14b
20a
12b
104a
104
114

Fig. 17a



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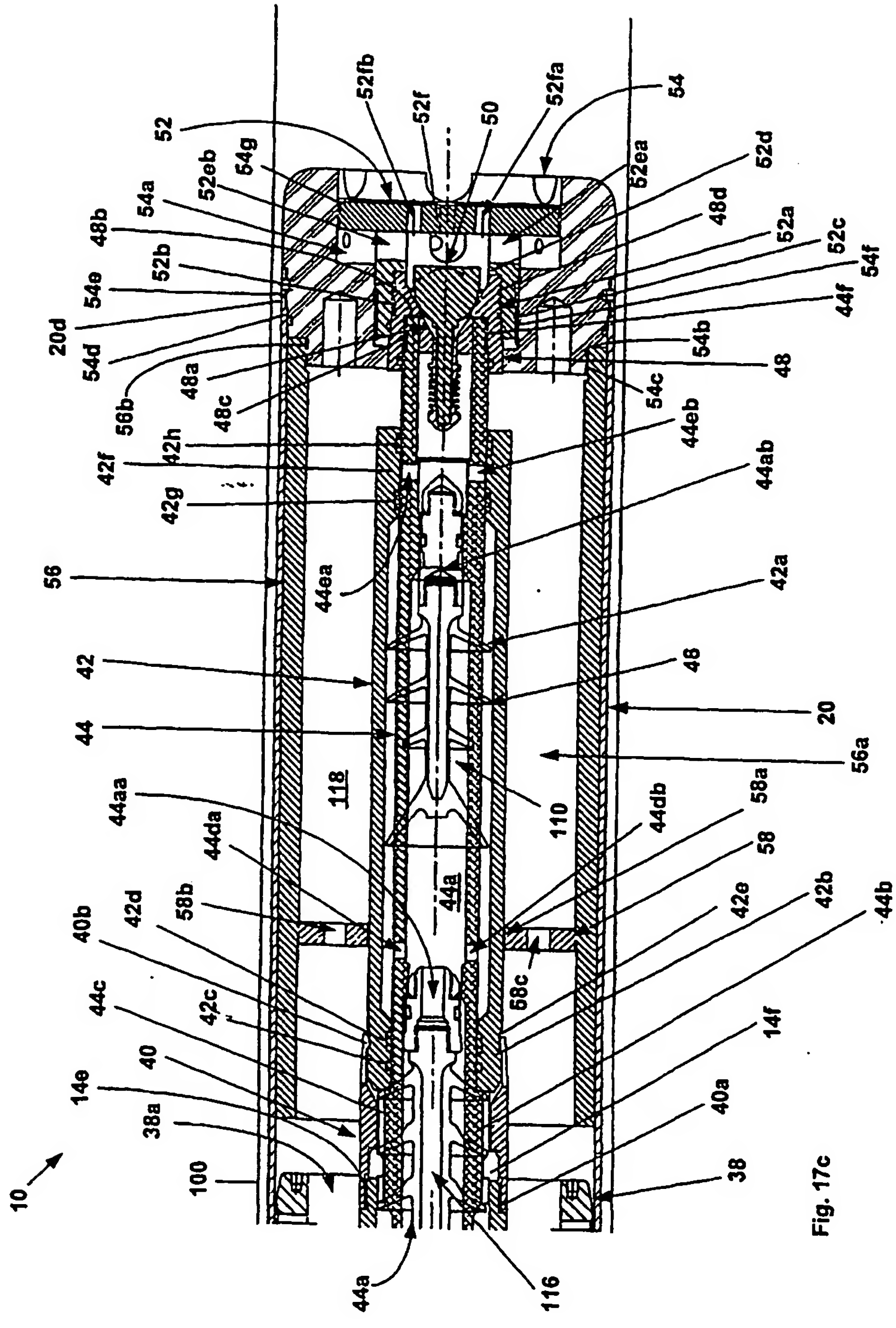
14f
38a
14e
38c
14i
16f
14g
36
14d
16g
16
20
14
28
30
14a
14c
34a
30a
114
44a
44
44b
32
44c
34
40
40a
34b
38
14j
38b
14h
26c
20b
26
100
26b

Fig. 17b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14e
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58b
44da
44aa
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44
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42g
42f
42h
48c
48a
56b
54d
20d
54e
52b
48b
54a
52eb
54g
52
52fb
52f
50
52fa
54
52ea
52d
48d
52a
52c
54f
44f
54b
48
54c
44eb
44ab
44ea
42a
46
20
110
56a
44db
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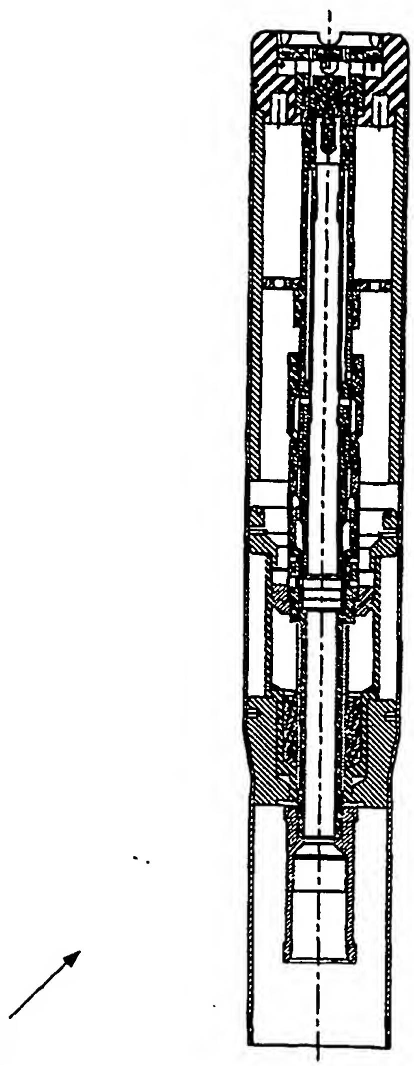
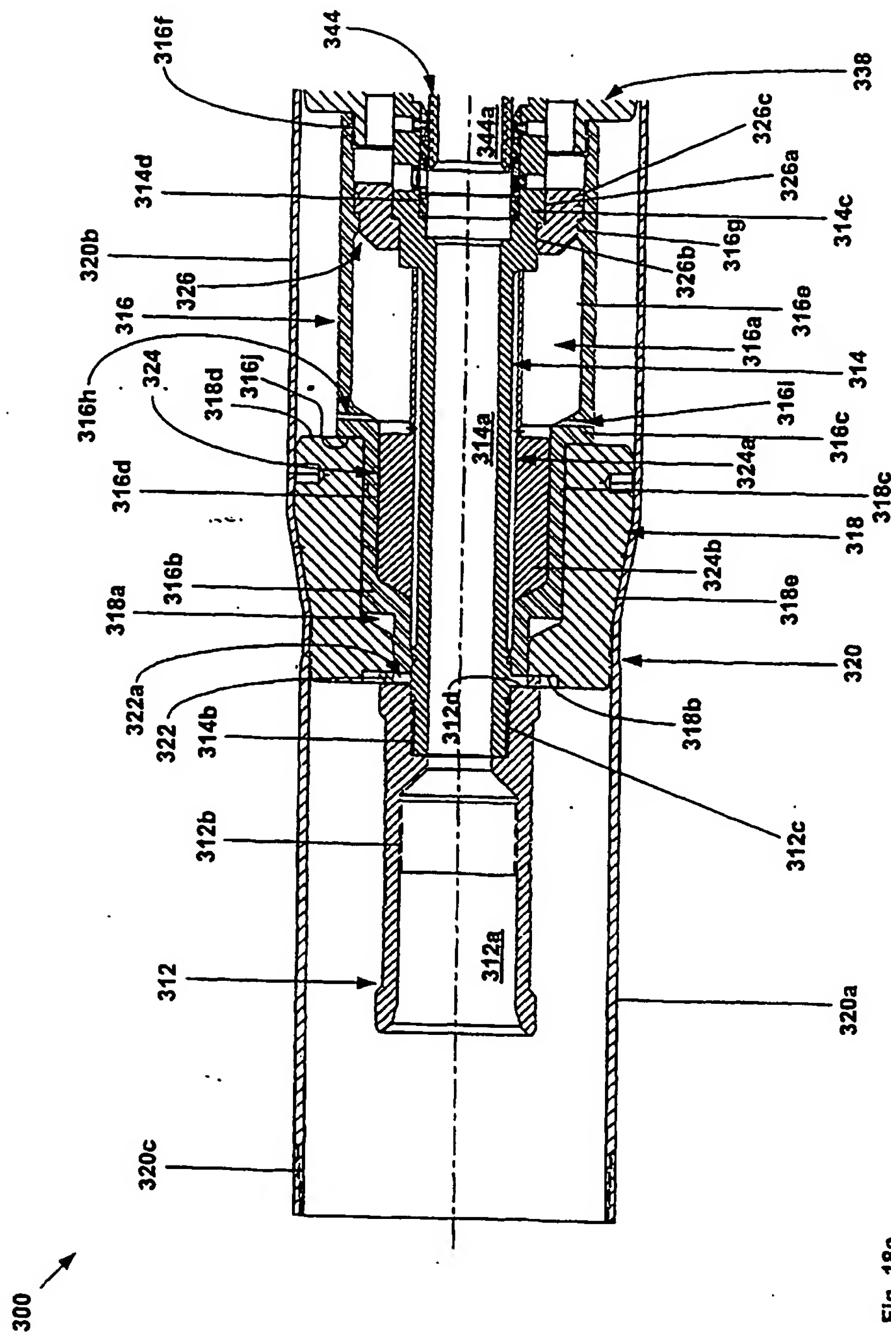
58
42e
42b
44b
58c
44a
14f
40a
38
116
44a

Fig. 17c



300

Fig. 18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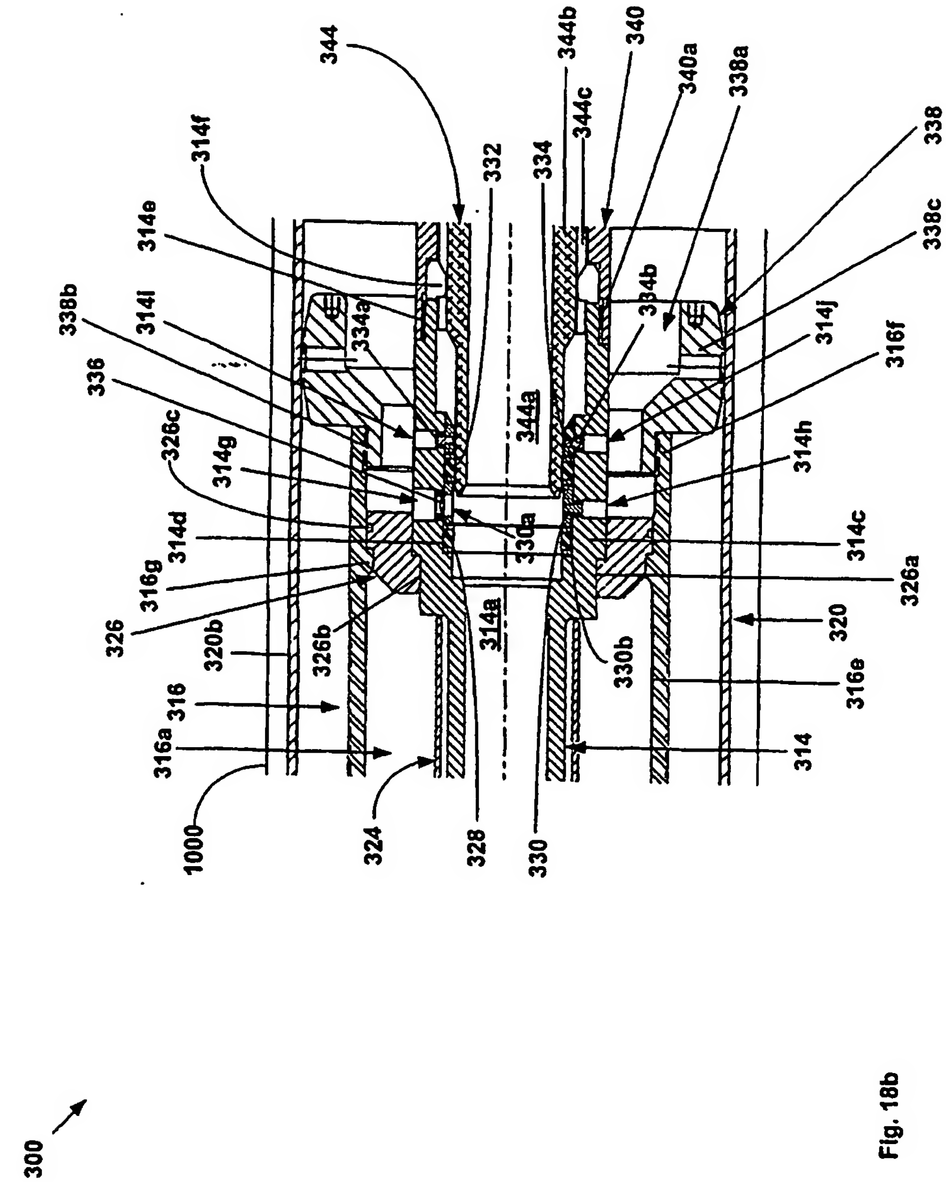
338
344a
314d
326c
326a
314c
320b
326
316g
326b
316
316e
316a
314
316h
324
318d
316j
316i
314a
316c
324a
316d
318c
318
324b
316b
318a
318e
320
322a
322
314b
312d
318b
312c
312b
312
312a
320a
320c
300

Fig. 18a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344c
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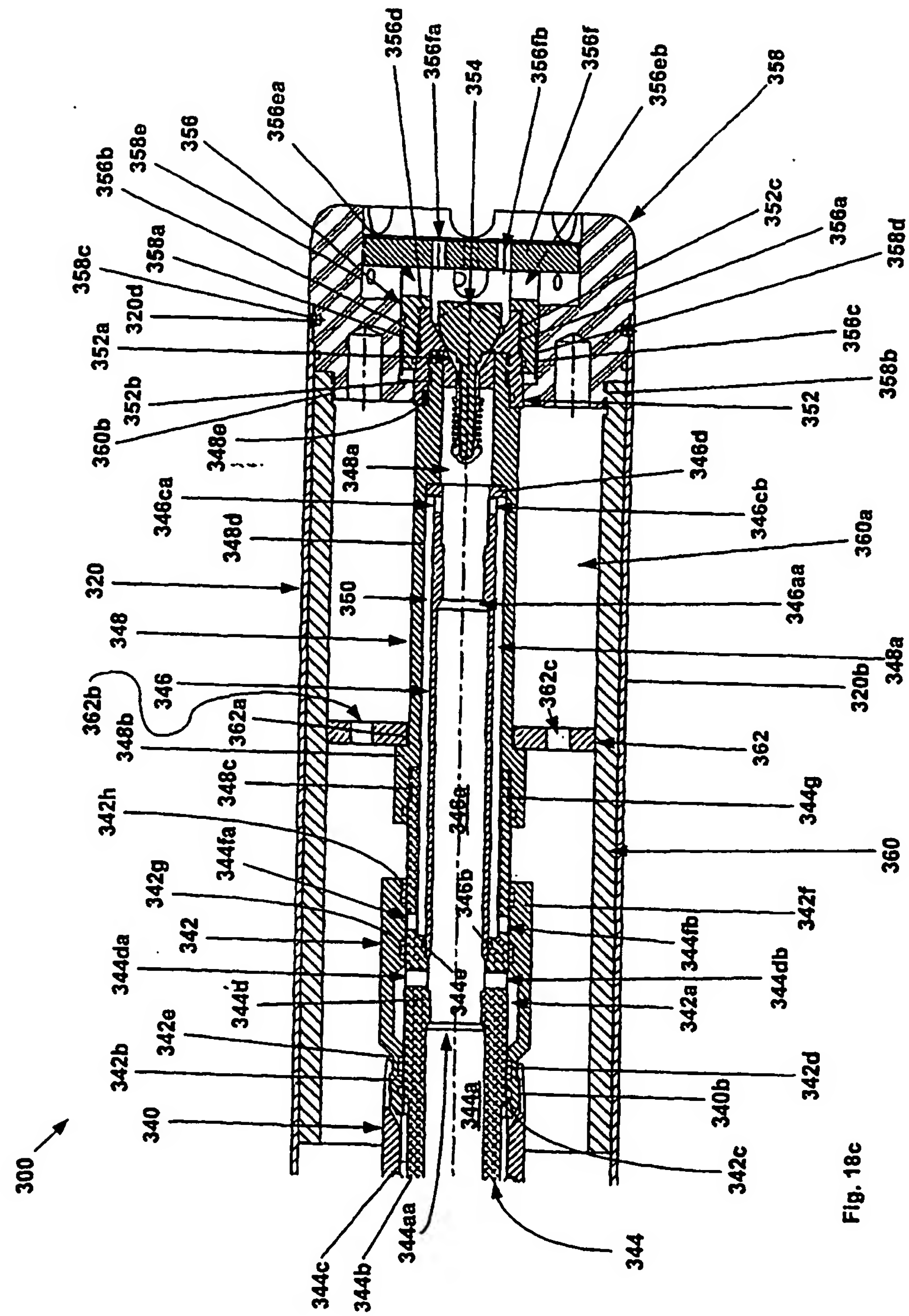
338c
338b
314i
334a
334b
314j
316f
336
326c
314g
344a
314h
314d
330a
314c
316g
326
326a
320b
326b
314a
330b
320
316
316e
316a
314
1000
324
328
330

Fig. 18b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344da
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342g
344fa
342h
348c
348b
362b
362a
346
348
350
320
348d
346ca
348a
348e
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
346aa
348a
320b
362c
362
344g
346a
360
342f
346b
344e
344fb
344db
342a
344a
342d
340b
342c
344
344aa
344b
344c

Fig. 18c

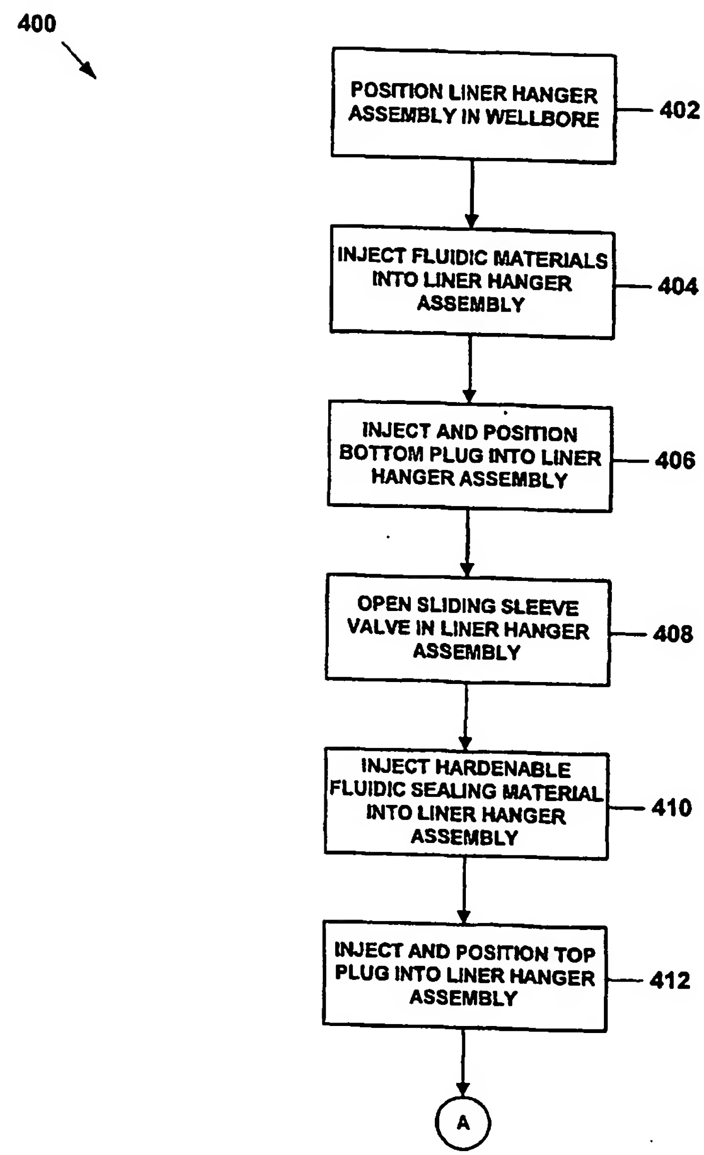

400
POSITION LINER HANGER ASSEMBLY IN WELLBORE
402
INJECT FLUIDIC MATERIALS INTO LINER HANGER ASSEMBLY
404
INJECT AND POSITION BOTTOM PLUG INTO LINER HANGER ASSEMBLY
406
OPEN SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
408
INJECT HARDENABLE FLUIDIC SEALING MATERIAL INTO LINER HANGER ASSEMBLY
410
INJECT AND POSITION TOP PLUG INTO LINER HANGER ASSEMBLY
412
A

Fig. 19a

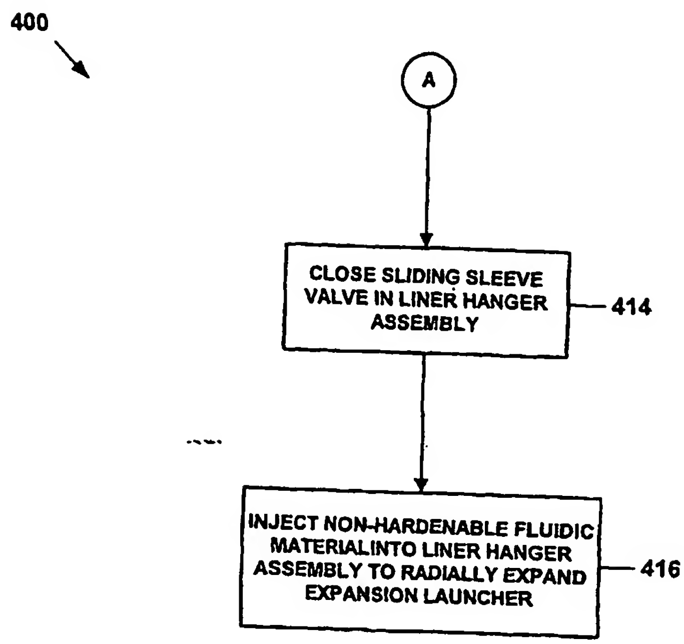
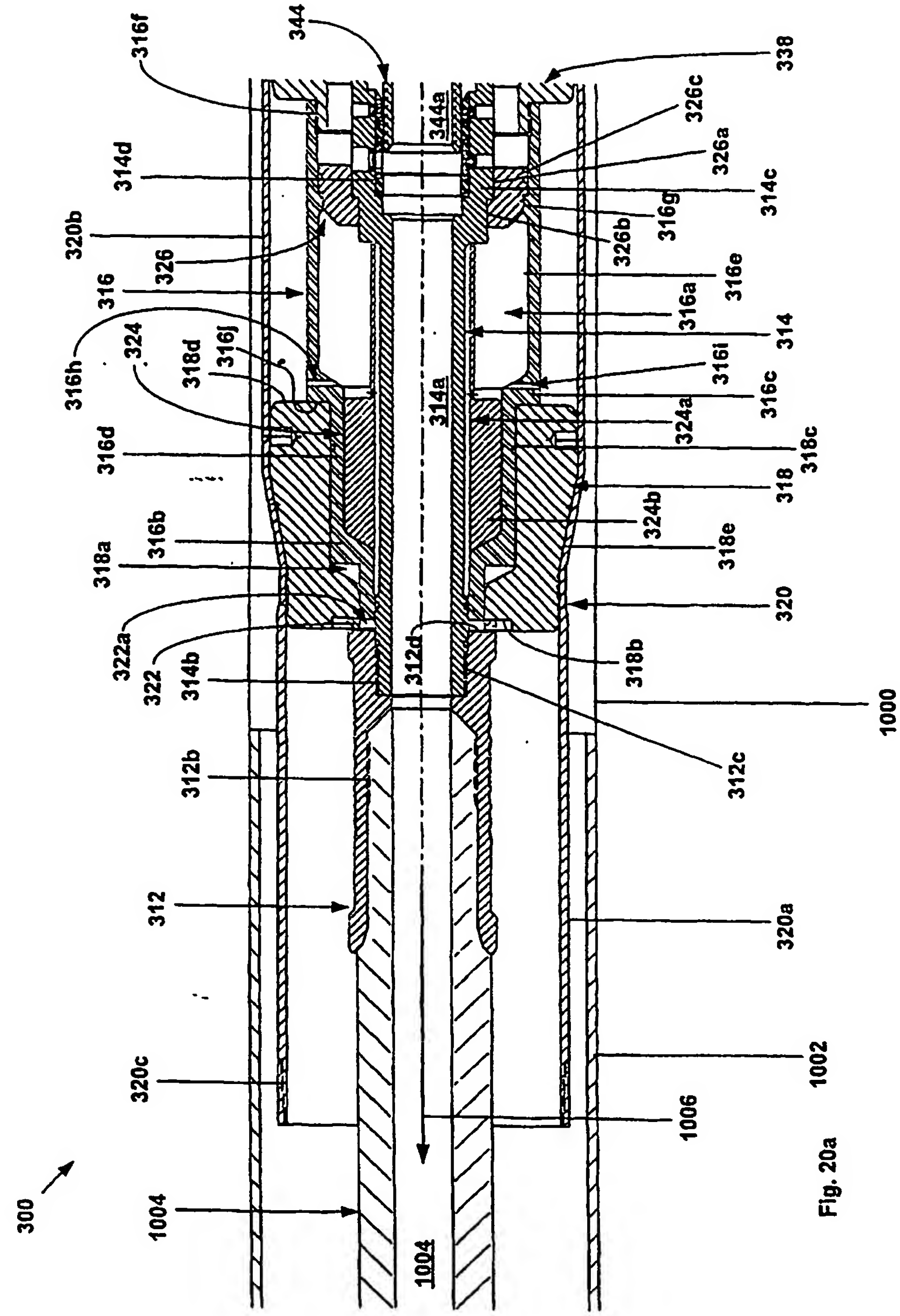

400
A
CLOSE SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
414
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
416

Fig. 19b



316f
344
344a
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326c
326a
314d
314c
316g
326b
320b
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316e
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316a
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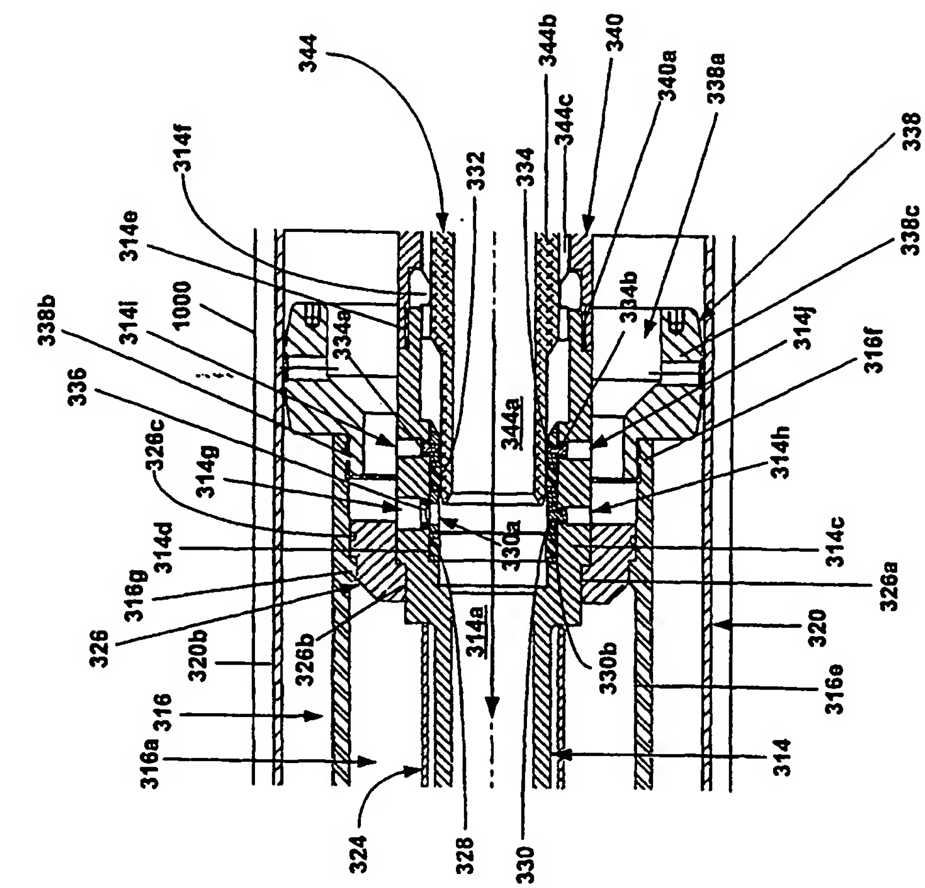
316h
324
318d
316j
316i
316c
314a
324a
316d
318c
318
324b
316b
318e
318a
320
322a
312d
318b
322
314b
1000
312c
312b
312
320a
320c
1002
1006
300
1004
1004

Fig. 20a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344b
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338a
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338c
1000
314i
338b
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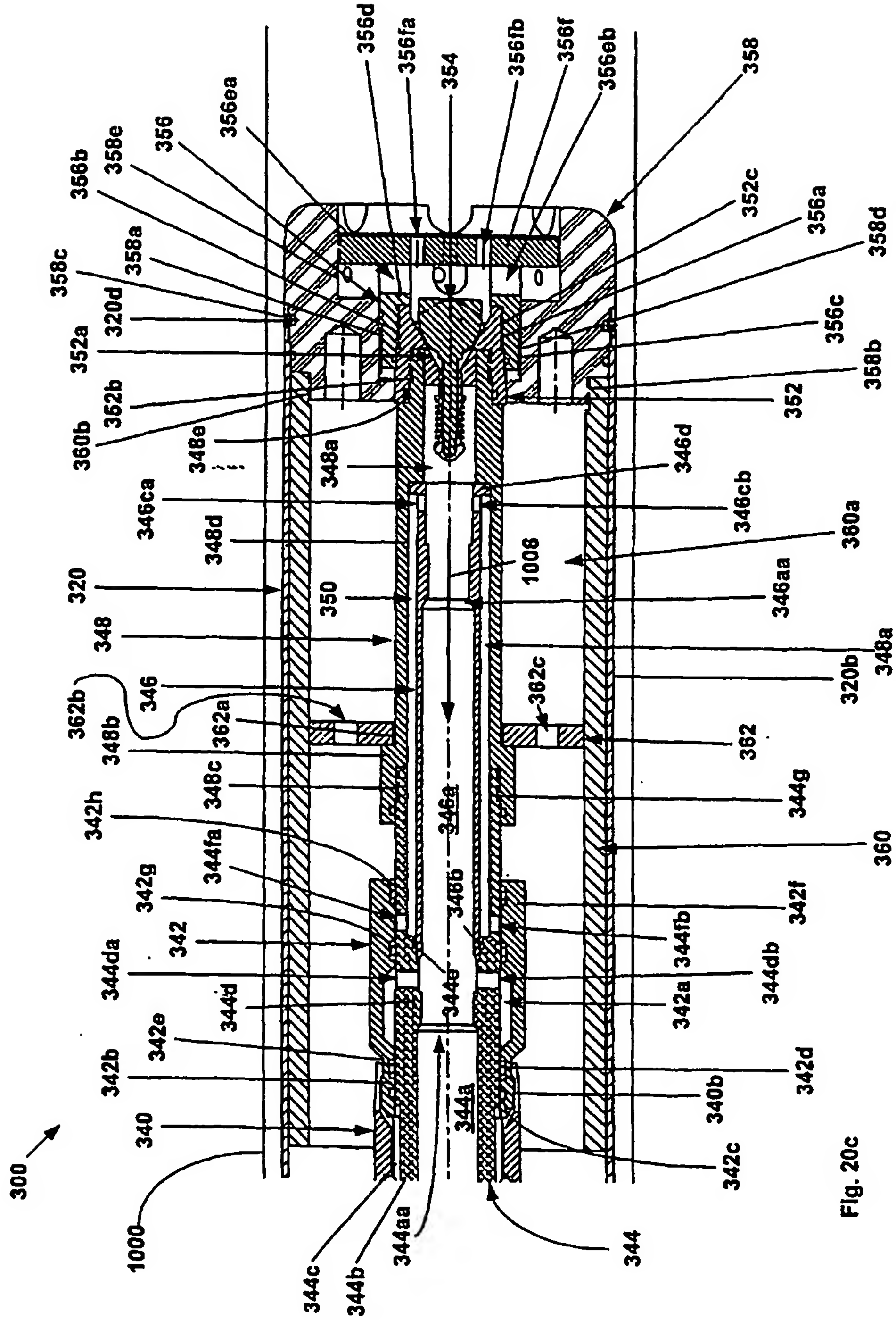
314j
316f
336
326c
314g
344a
330a
314h
314d
314c
316g
326
326b
326a
320b
314a
330b
320
316
316e
316a
324
328
330
314

Fig. 20b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342g
342h
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344a
344aa
344b
344c
344d
344da
344db
344e
344fa
344fb
344g
346
346a
346aa
346b
346ca
346cb
346d
348
348a
348b
348c
348d
348e
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352
352a
352b
352c
354
356
356a
356b
356c
356d
356ea
356eb
356f
356fa
356fb
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358c
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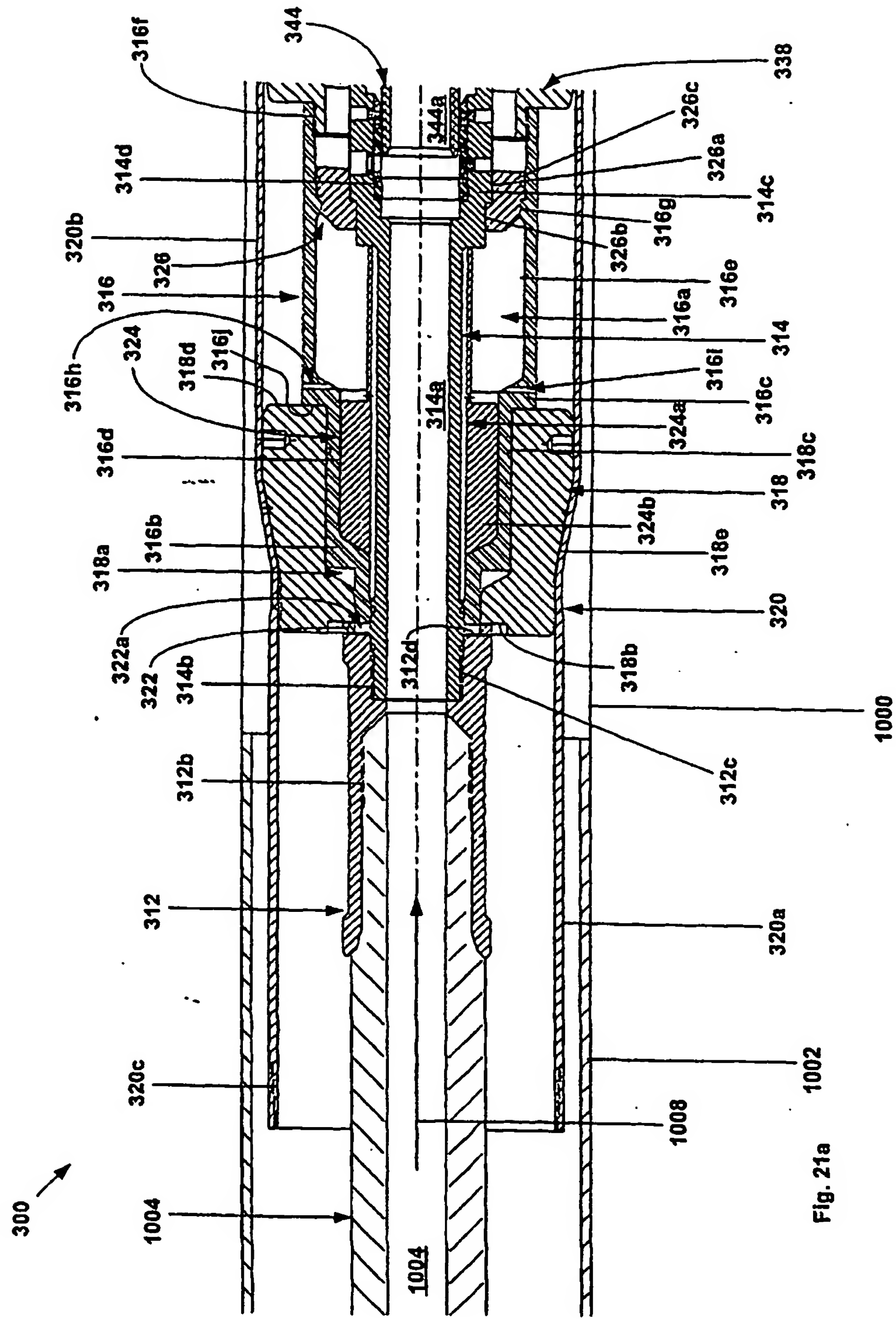
360
360a
360b
362
362a
362b
362c
1006

Fig. 20c


316f
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338
344a
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320b
326b
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316e
316
316a
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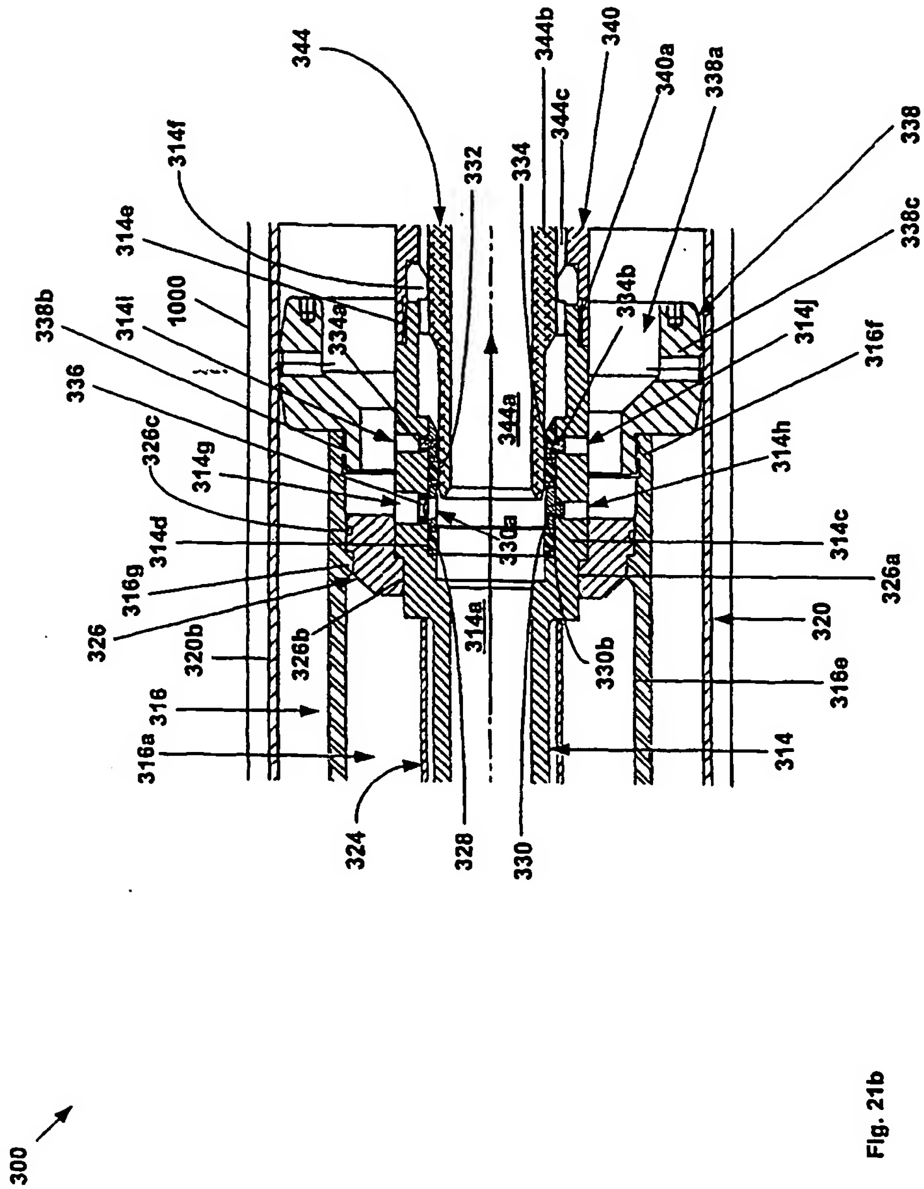
316h
318d
316j
316i
316c
314a
324a
316d
318c
318
324b
316b
318e
318a
320
322a
312d
318b
322
314b
1000
312c
312b
312
320a
320c
1002
1008
300
1004
1004

Fig. 21a



344
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340a
338a
338
338c
314f
332
334
344c
314e
1000
314l
338b
334a
334b
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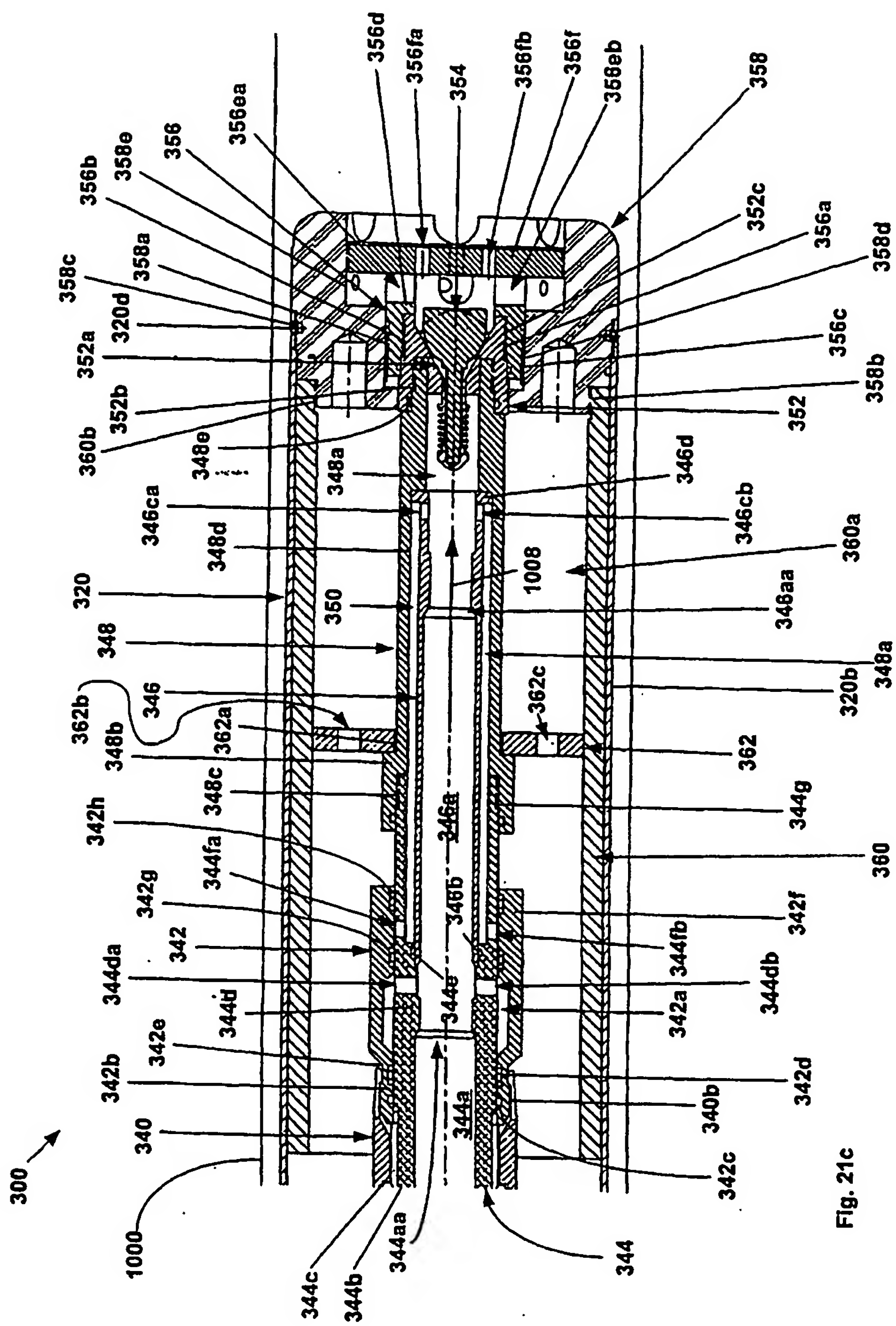
316f
336
326c
314g
344a
314h
314d
330a
314c
316g
326a
326
326b
314a
330b
320
320b
316
316a
316e
314
324
328
330
300

Fig. 21b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344d
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342g
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342h
348c
348b
362a
362b
346
348
320
350
348d
346ca
348a
348e
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
1008
348aa
348a
320b
362c
362
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346a
360
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344db
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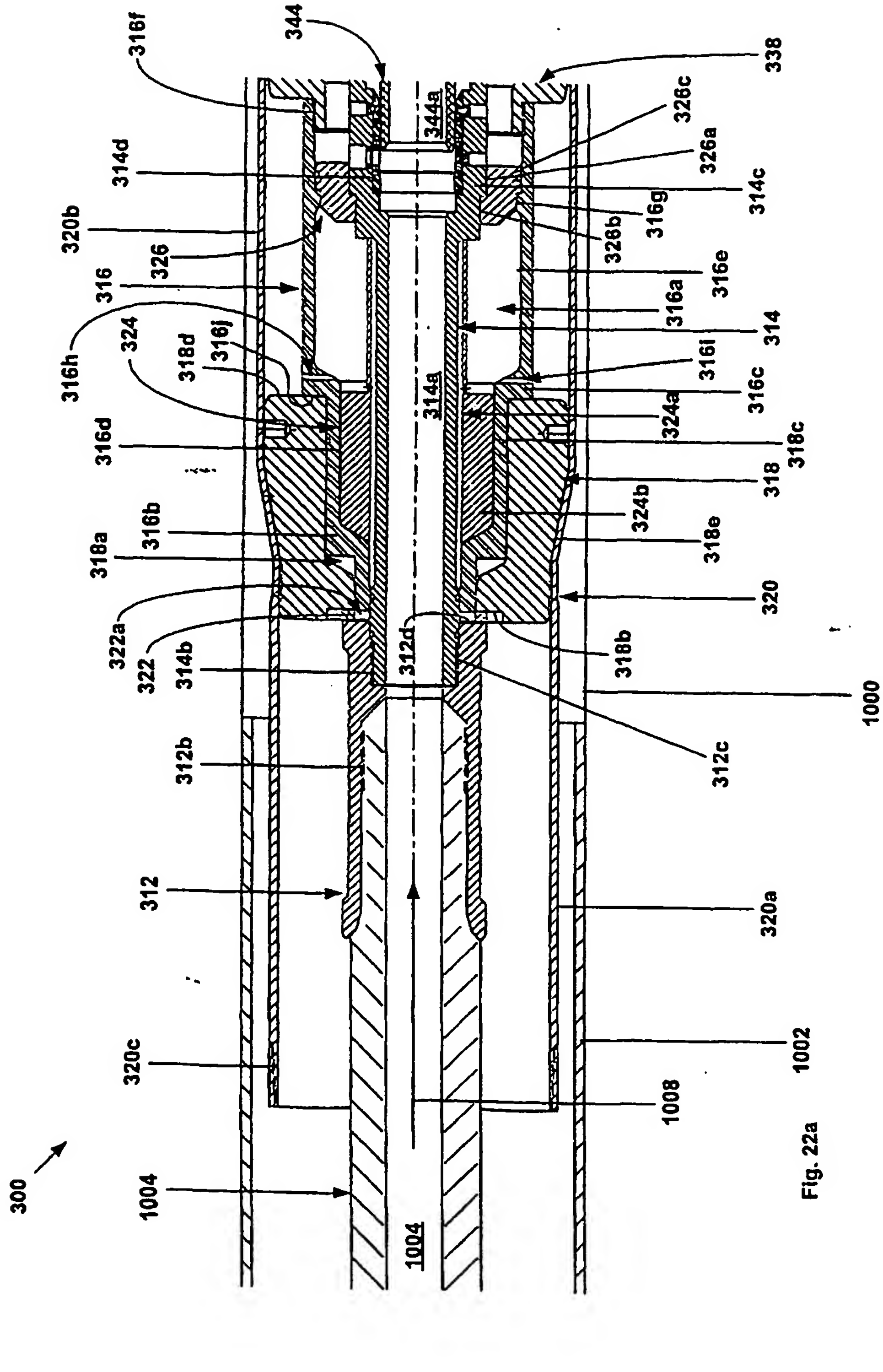
342c
344a
344
344aa
344b
344c

Fig. 21c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314c
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326b
326
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316e
316a
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318d
316j
316i
314a
316c
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316d
318c
318
324b
316b
318e
318a
320
322a
322
314b
312d
318b
1000
312c
312b
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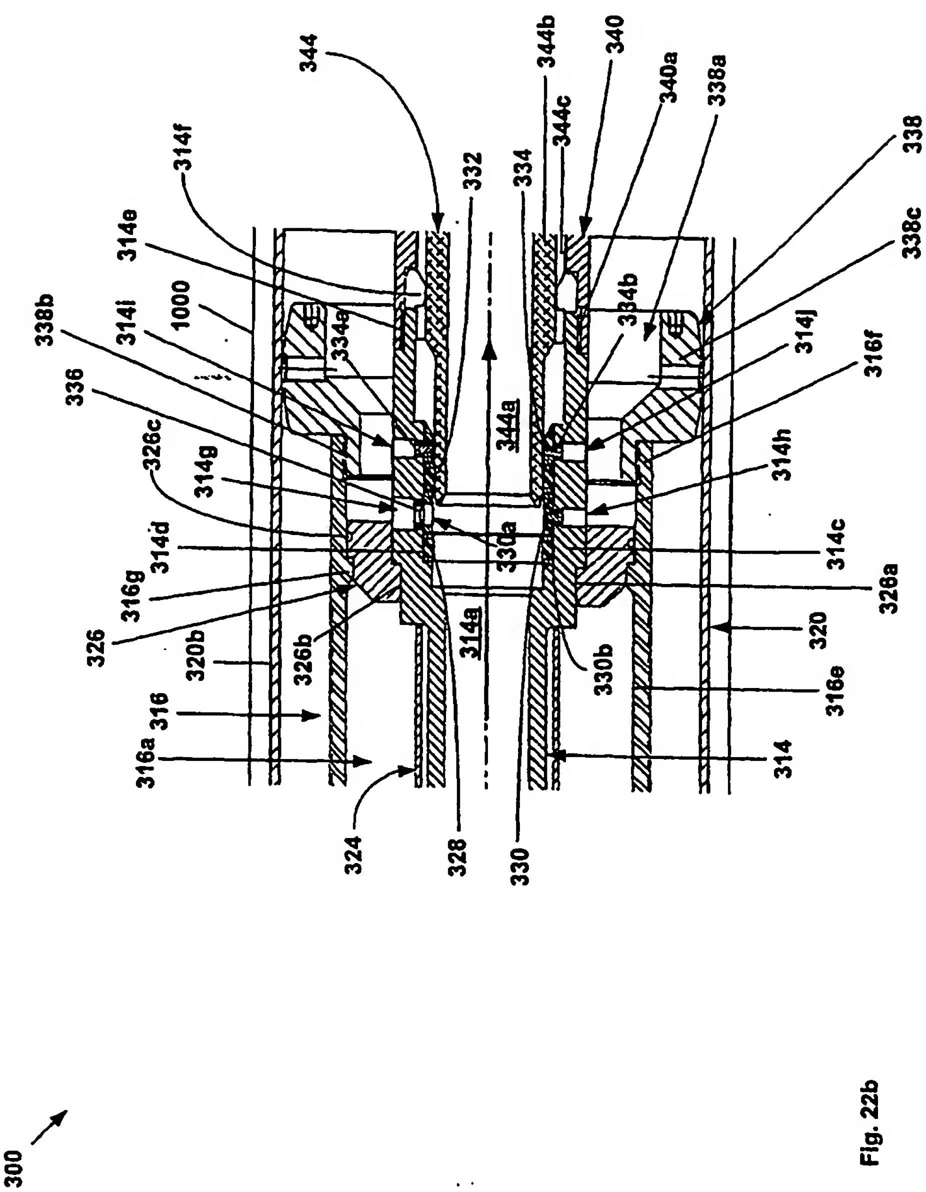
320a
320c
1002
1008
1004
1004

Fig. 22a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340a
338a
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338c
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1000
334b
314j
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334e
344a
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326c
314g
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330a
314d
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316e
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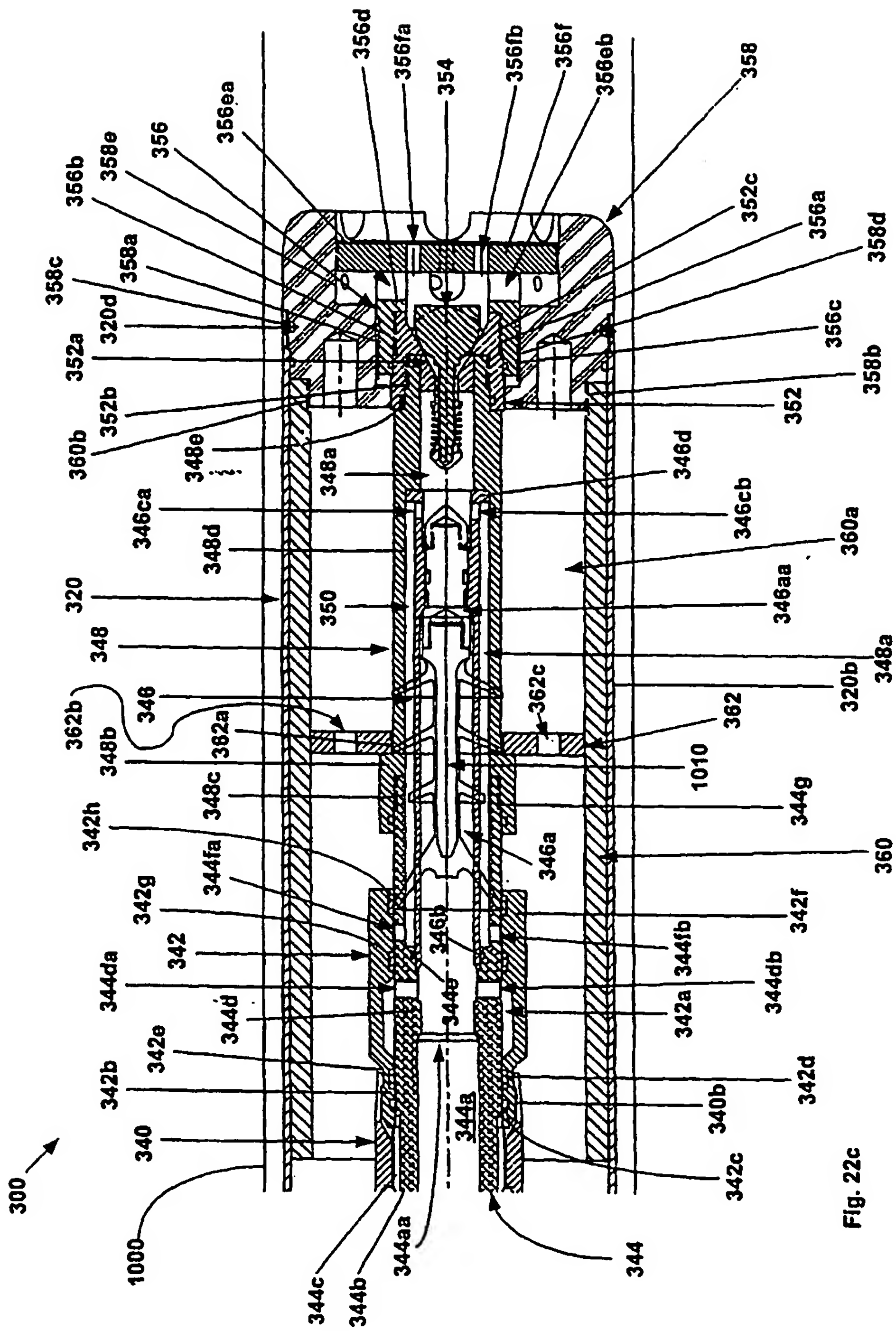
328
330
314

Fig. 22b


300
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362b
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348e
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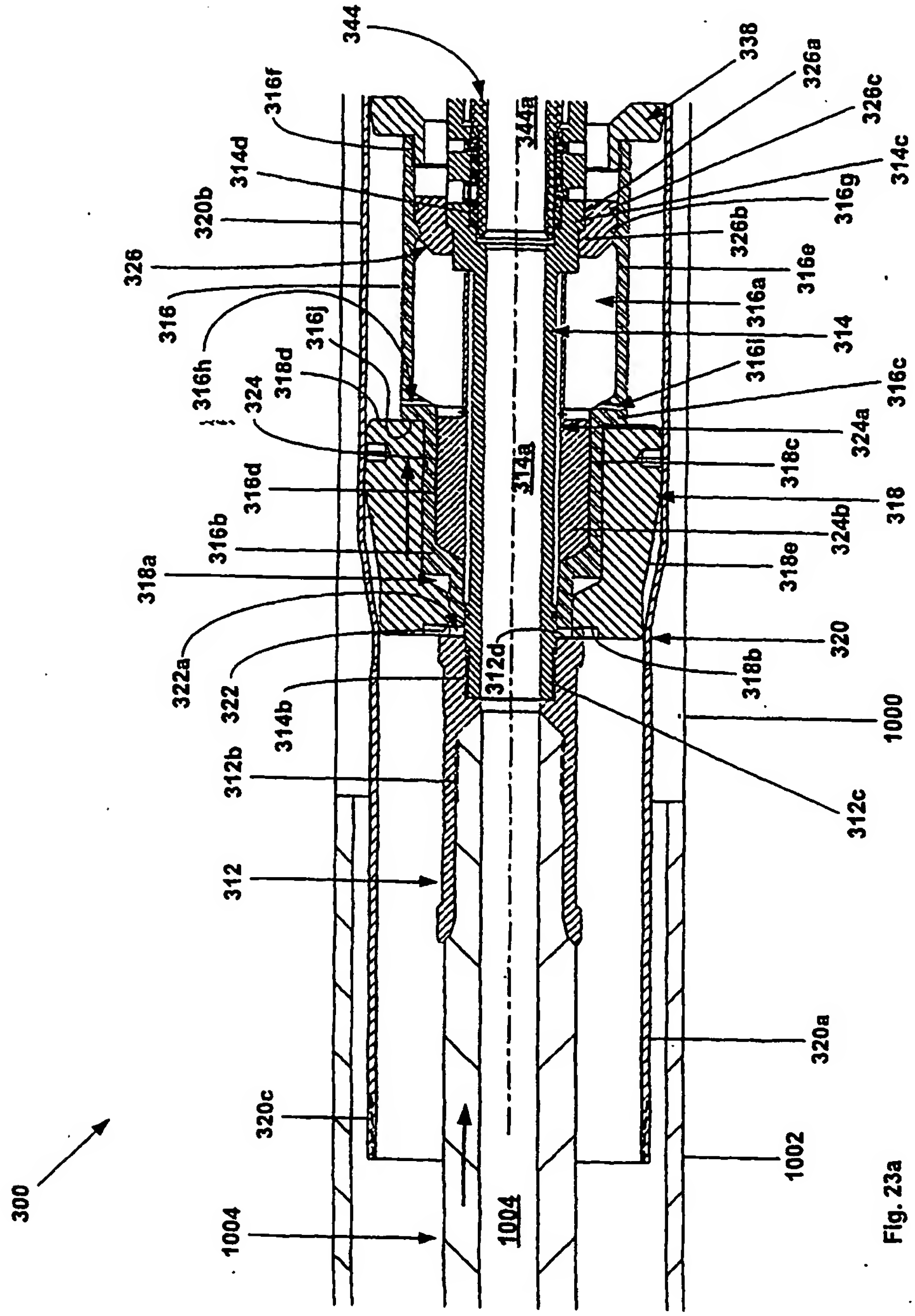
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
346aa
348a
320b
362c
362a
362
1010
344g
346a
360
342f
346b
344fb
344e
344db
342a
342d
340b
342c
344a
344aa
344b
344c
344

Fig. 22c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326c
314c
316f
314d
320b
316g
326b
326
316e
316a
316
314
316h
316j
318d
316i
316c
324
324a
318c
316d
314a
318
316b
324b
318a
318e
322a
320
322
312d
318b
314b
1000
312b
312c
312
320a
320c
1002
1004
1004

Fig. 23a

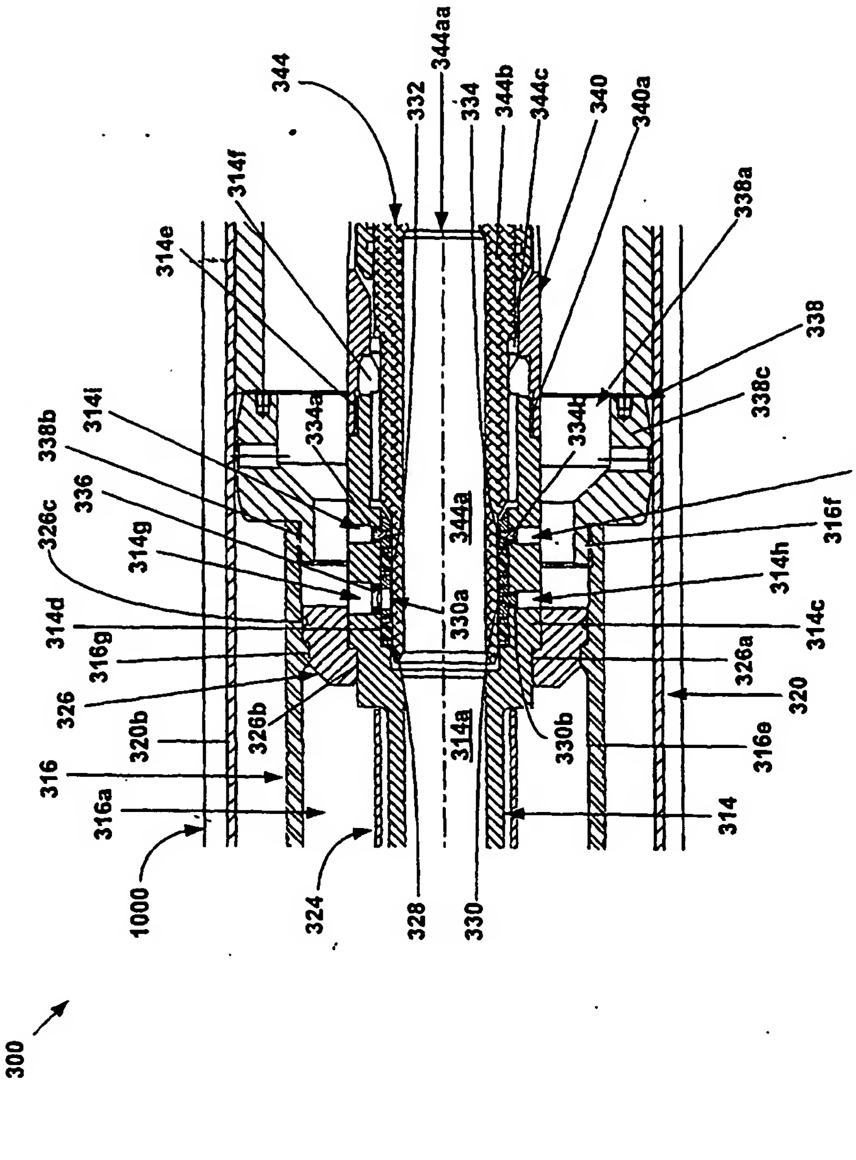
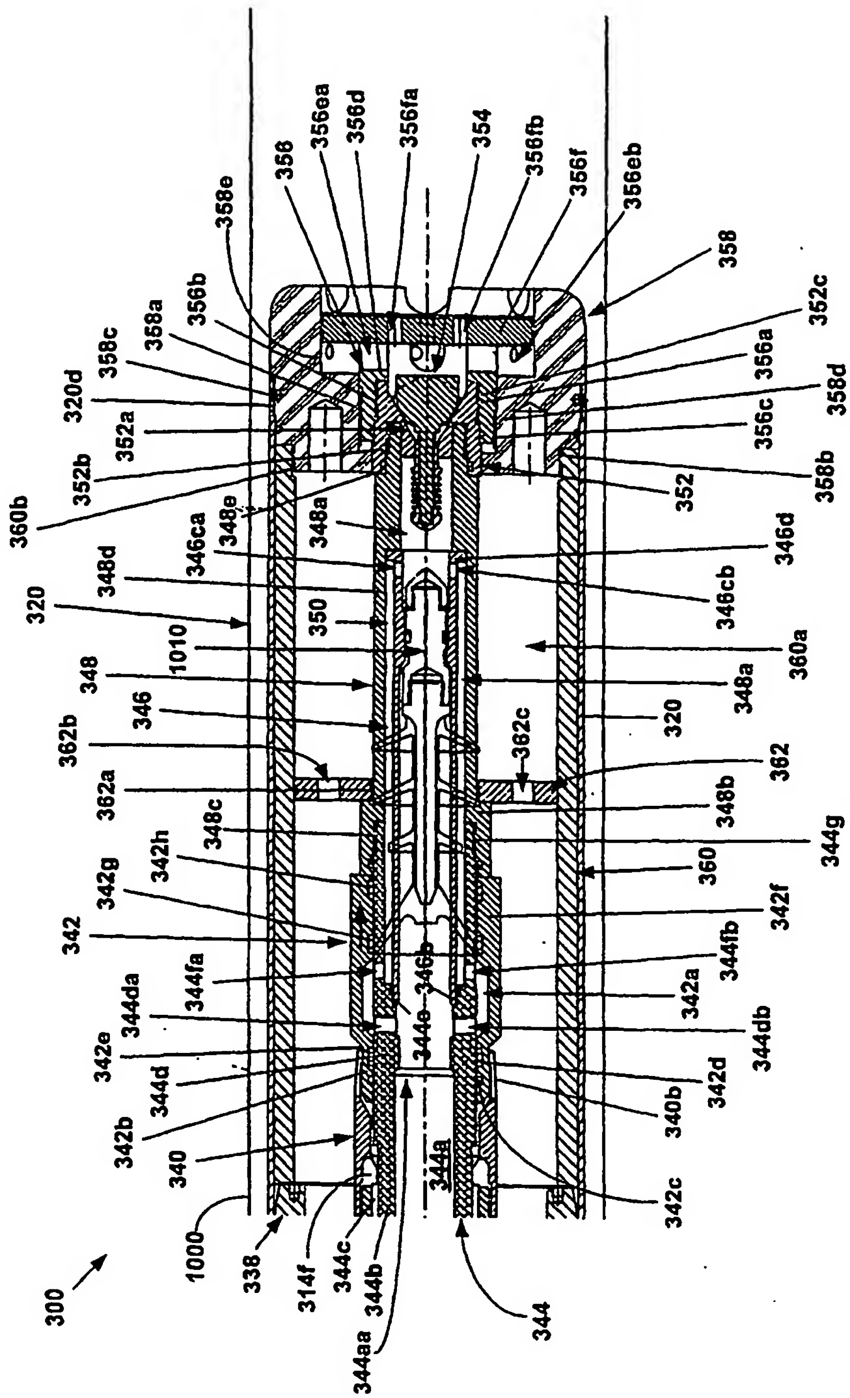

300
1000
316a
316
320b
326
316g
314d
326c
314g
336
338b
314i
314e
314f
344
332
344aa
334
344b
344c
340
340a
338a
338
338c
314j
316f
314h
314c
326a
320
316e
314
330b
330
328
324
326b
334a
334b
330a
344a
314a

Fig. 23b


300
1000
338
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344c
344b
344aa
344
344a
340
342b
344d
342e
344da
344fa
342
342g
342h
348c
362a
362b
346
348
1010
350
348d
346ca
348e
348a
320
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
348a
320
362c
362
348b
344g
360
342f
344fb
346b
344e
342a
344db
342d
340b
342c

Fig. 23c

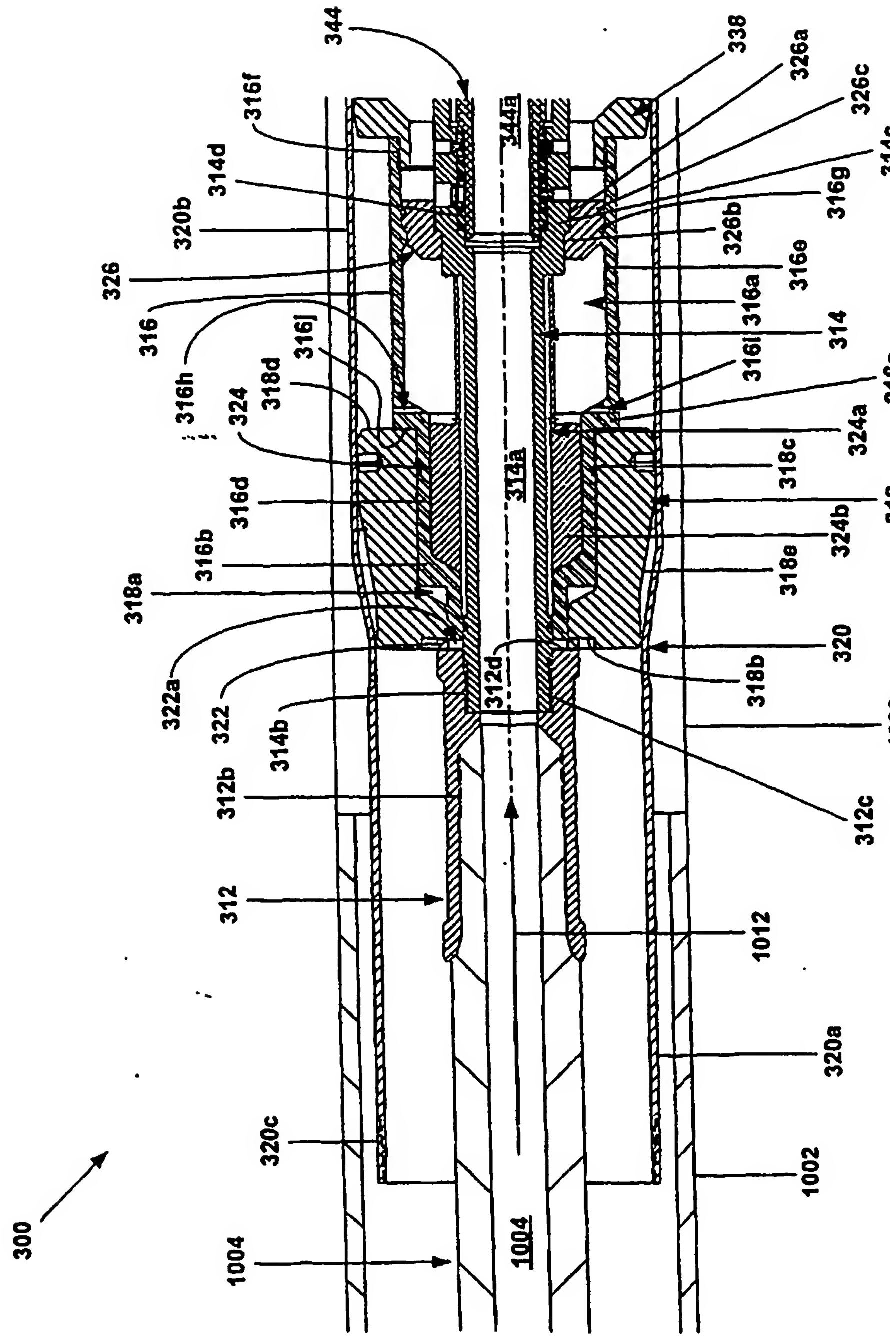

344
338
326a
326c
314c
316g
326b
316e
316a
314
316i
316c
324a
318c
318
324b
318e
320
318b
1000
312c
1012
320a
1002
316f
314d
320b
326
316
316j
318d
324
316h
316d
316b
318a
322a
322
314b
312b
312
320c
300
1004
344a
314a
312d
1004

Fig. 24a

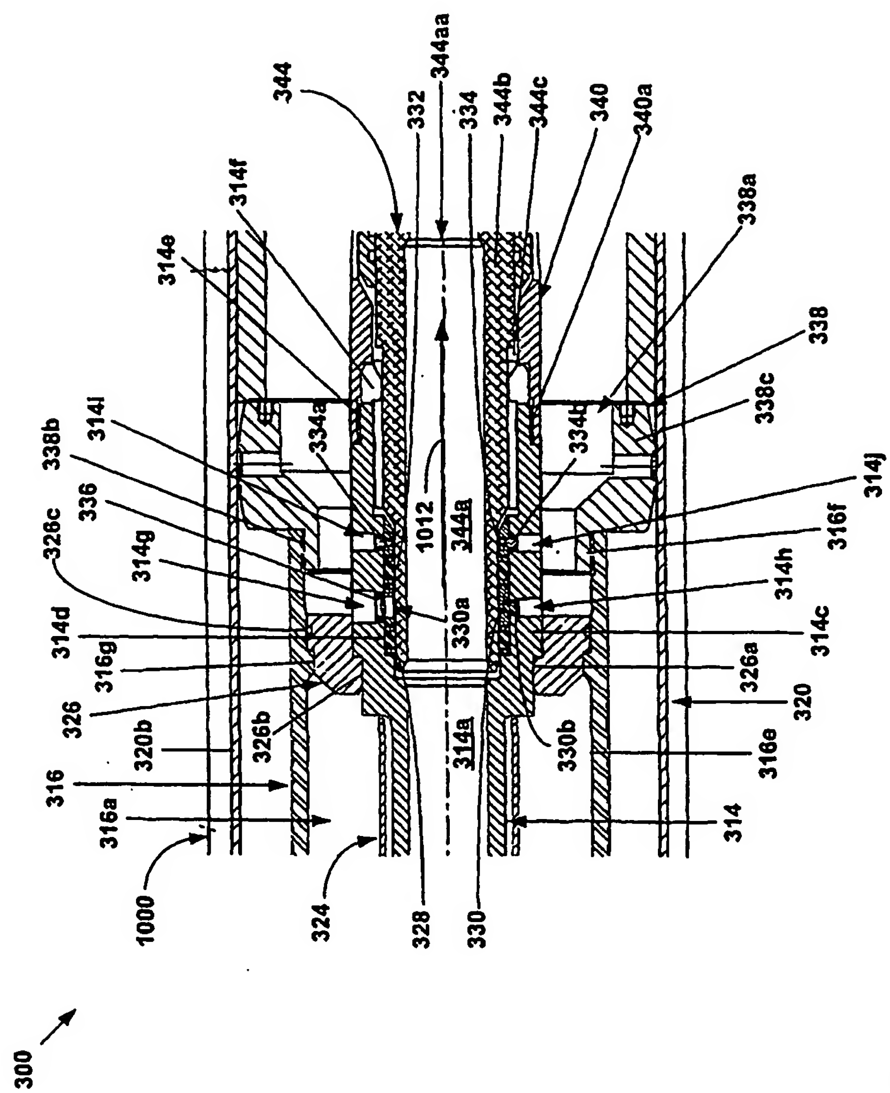
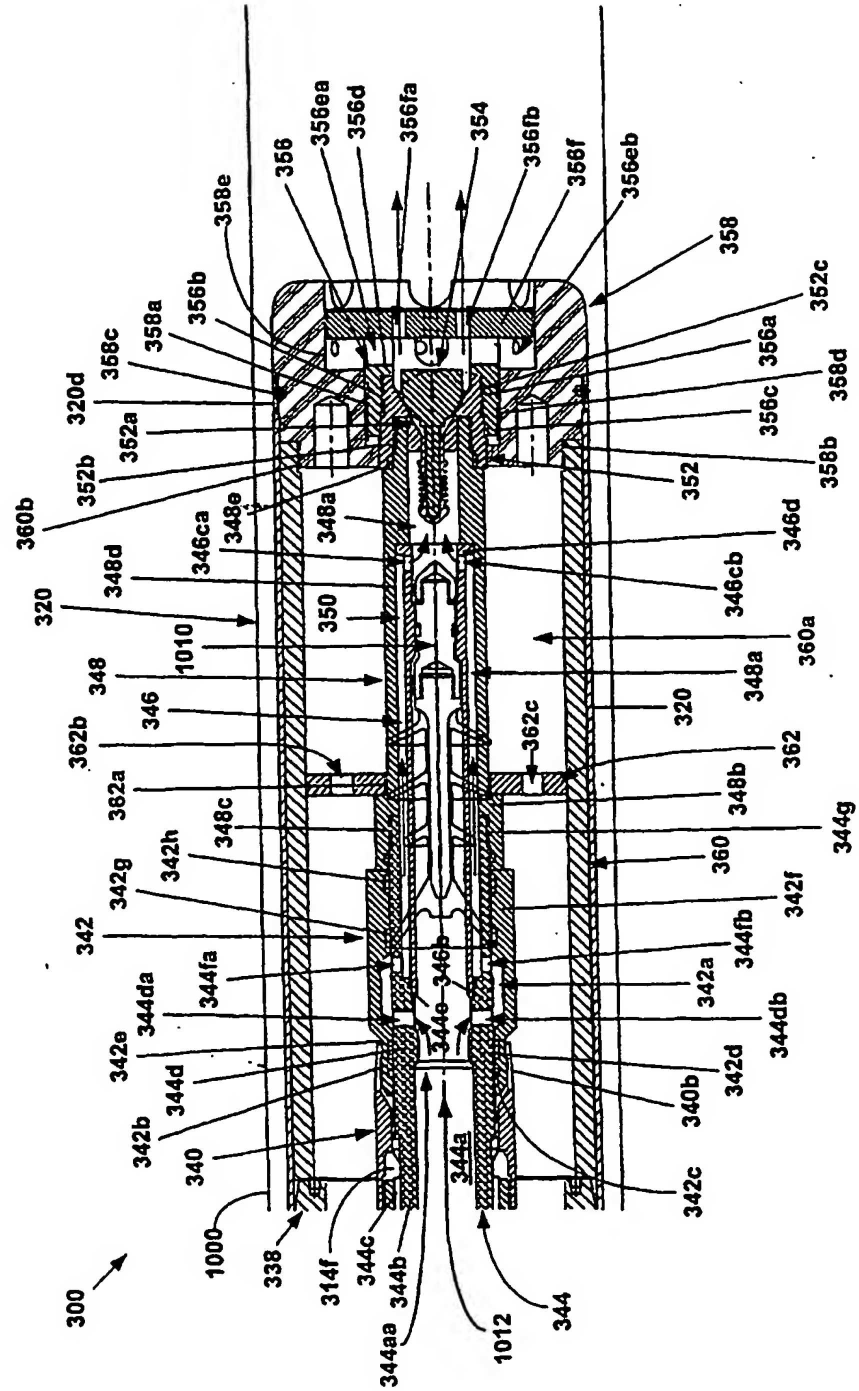

300
1000
324
328
330
316a
316
320b
326b
326
316g
314d
326c
314g
336
338b
314l
334a
314e
314f
344
332
344aa
334
344b
344c
340
340a
338a
338
338c
314j
316f
314h
314c
326a
320
316e
314
330b
314a
330a
344a
1012
334b

Fig. 24b


300
1000
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314f
344c
344b
344aa
1012
344
340
342b
344d
342e
344da
344fa
342
342g
342h
348c
362a
362b
346
348
1010
350
348d
346ca
348e
348a
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
348a
320
362c
362
348b
344g
360
342f
344fb
342a
344db
342d
340b
342c
344a
346b
344e
320

Fig. 24c

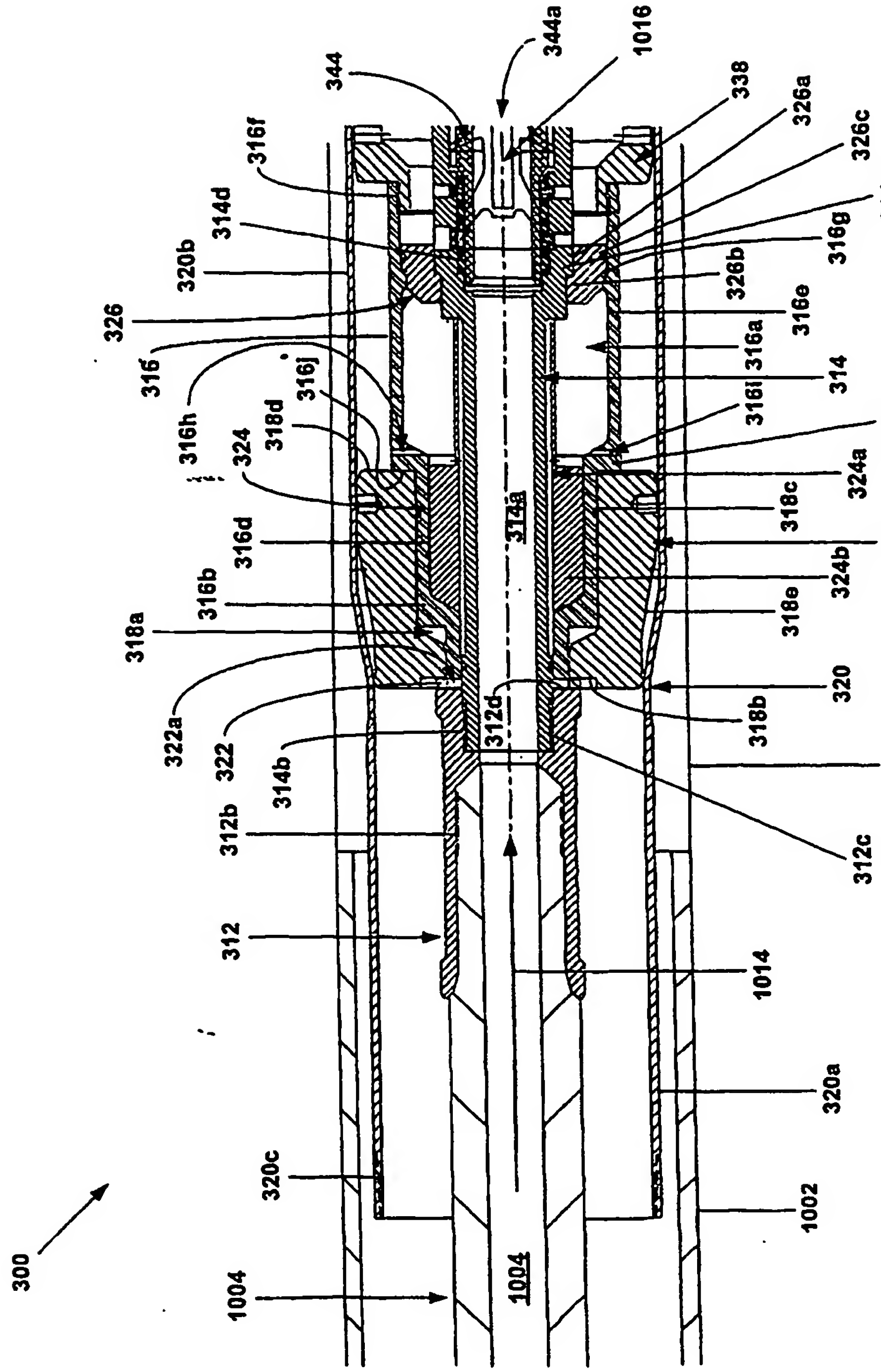

300
1004
1004
320c
312
312b
314b
322
322a
318a
316b
316d
324
318d
316j
316h
316
326
320b
314d
316f
344
344a
1016
338
326a
326c
314c
316g
326b
316e
316a
314
316i
316c
324a
318c
318
324b
318e
320
318b
1000
312c
312d
314a
1014
320a
1002

Fig. 25a

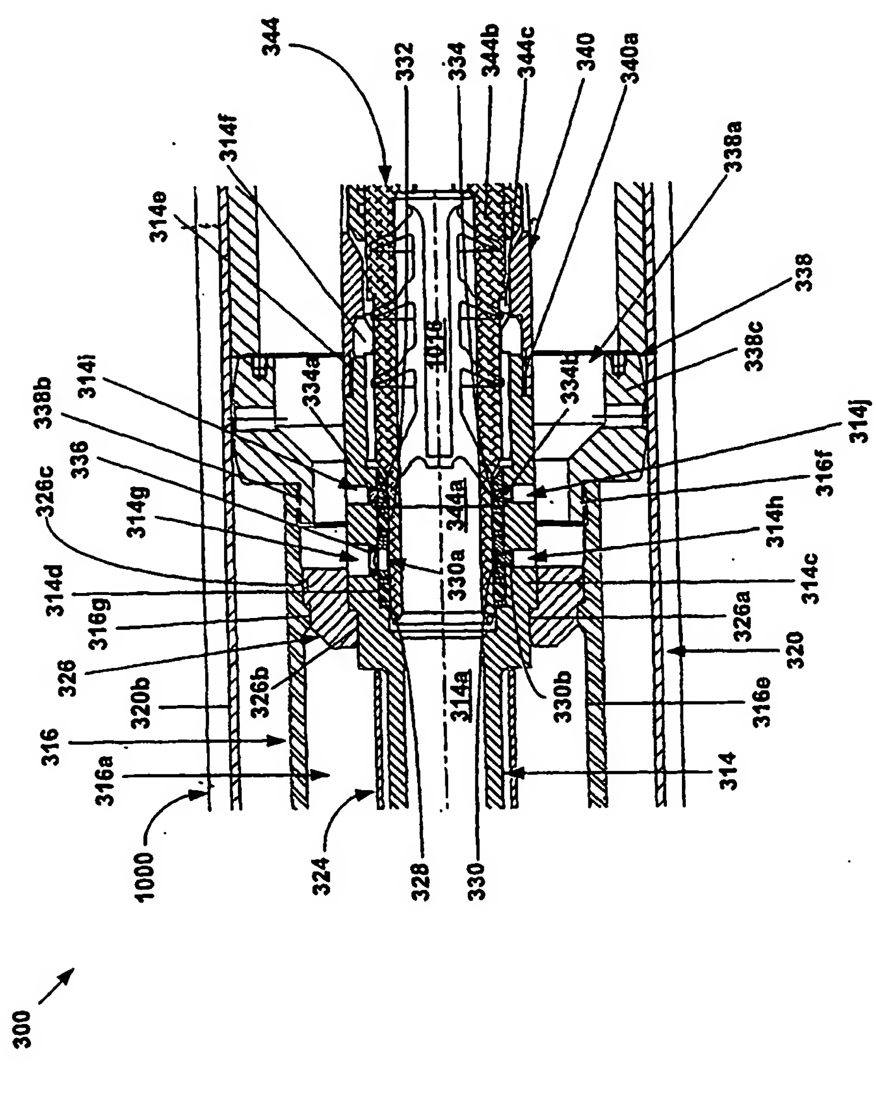

344
332
334
344b
344c
340
340a
338a
314f
314e
338
338c
338b
314i
334a
1016
334b
314j
336
326c
314g
344a
316f
314h
330a
314d
316g
314c
326a
326
326b
320b
330b
320
316
316a
314a
316e
314
1000
324
328
330
300

Fig. 25b

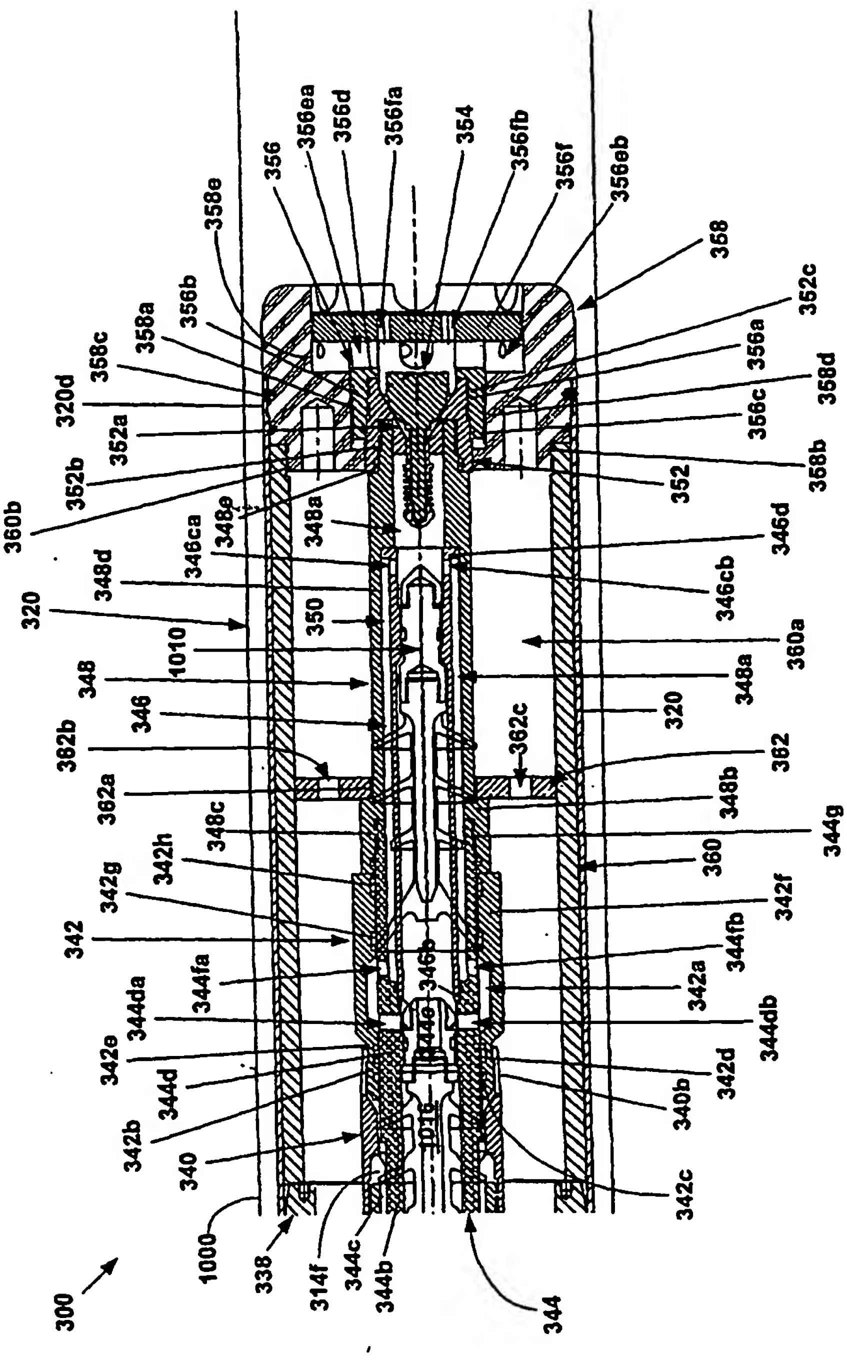
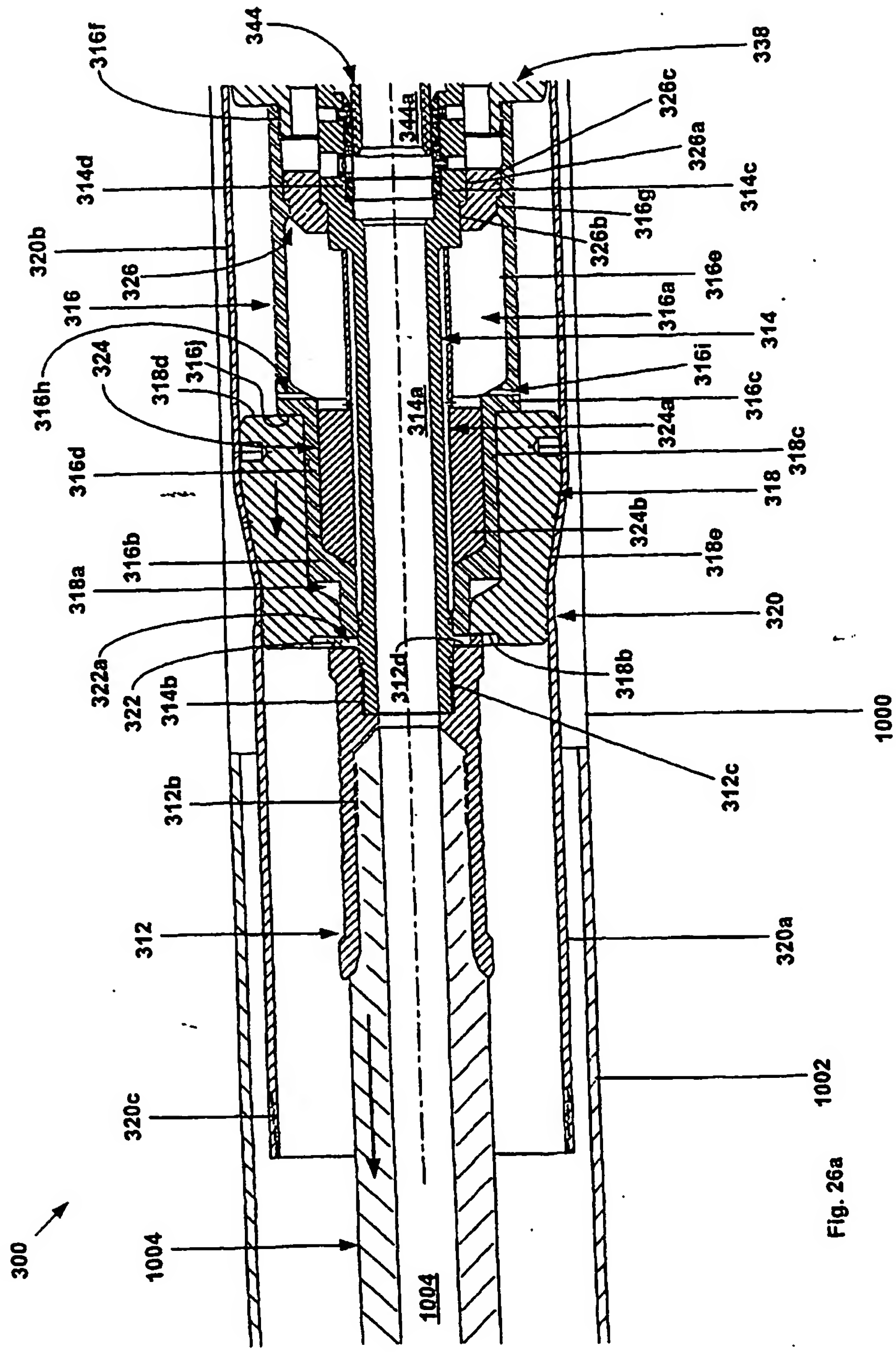

300
1000
338
314f
344c
344b
344
340
342b
344d
342e
344da
344fa
342
342g
342h
348c
362a
362b
346
348
1010
320
348d
346ca
348e
348a
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
350
362c
362
348b
344g
360
342f
344fb
342a
346b
344e
344db
342d
340b
1016
342c

Fig. 25c


344
338
316f
344a
326c
326a
314d
314c
316g
326b
320b
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316e
316
316a
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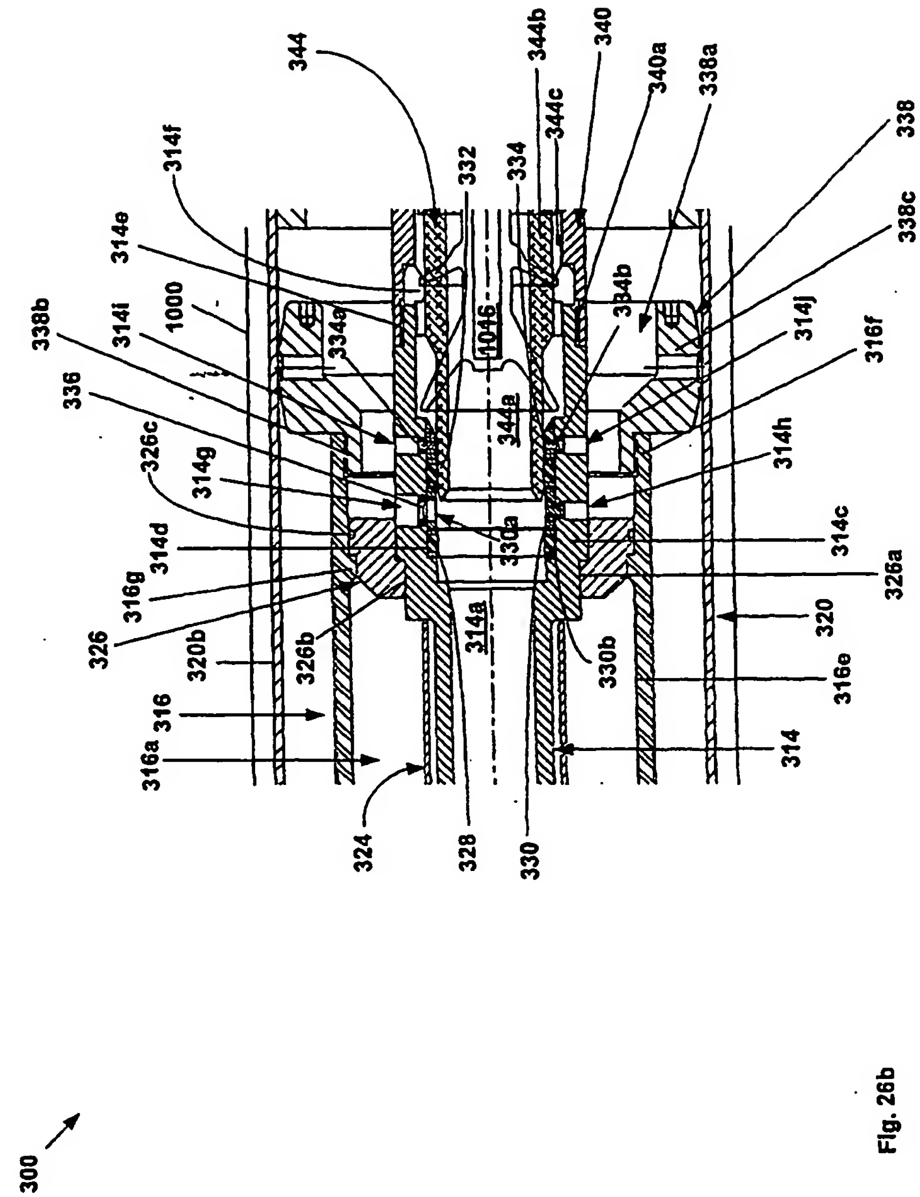
318d
316j
316i
316c
314a
324a
318c
316d
318
324b
316b
318e
318a
320
322a
322
314b
312d
318b
1000
312c
312b
312
320a
320c
1002
300
1004
1004

Fig. 26a


300
344
344b
340
340a
338a
338
338c
314f
332
334
344c
314e
1000
314i
338b
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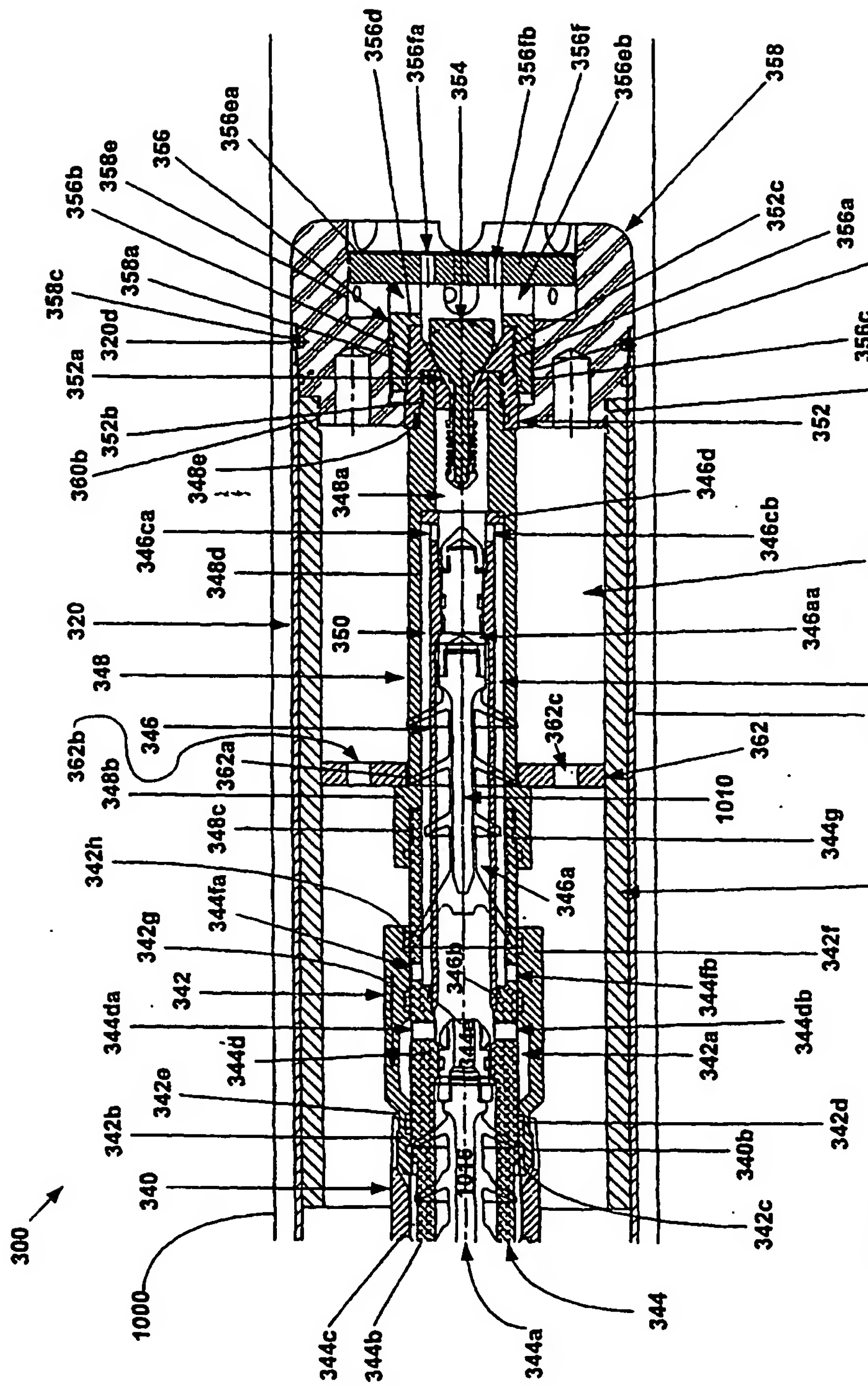
334b
314j
316f
336
326c
314g
344a
314h
314d
330a
314c
316g
326a
326
326b
314a
320b
320
330b
316e
316
316a
314
324
328
330

Fig. 26b


300
1000
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344b
344a
344
340
342b
342e
344d
344da
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342g
344fa
342h
348c
348b
362a
346
362b
348
320
350
348d
346ca
348a
348e
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
346aa
348a
320b
362c
362
1010
344g
346a
360
342f
346b
344fb
344db
342a
342d
340b
342c
1016
344e

Fig. 26c

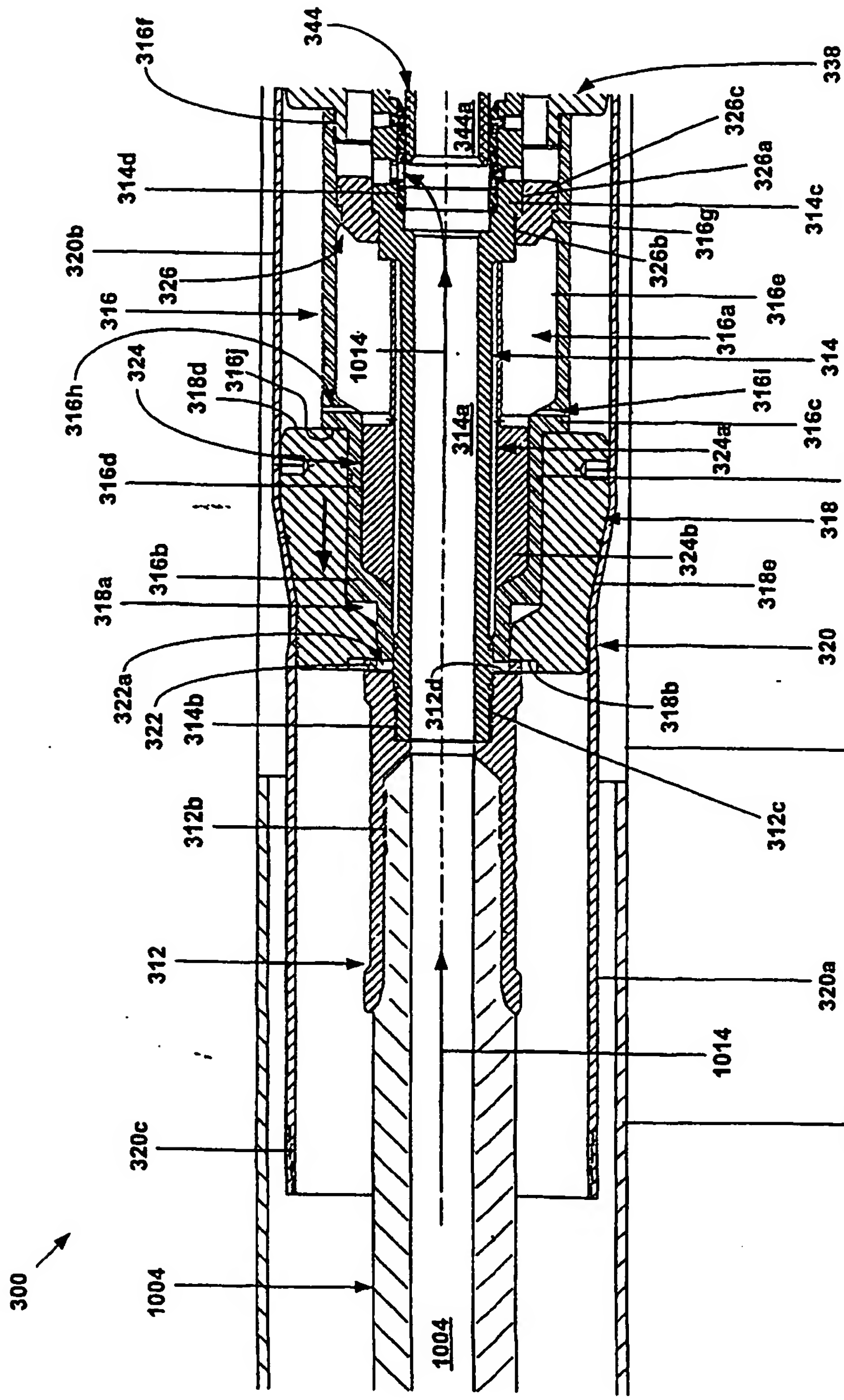
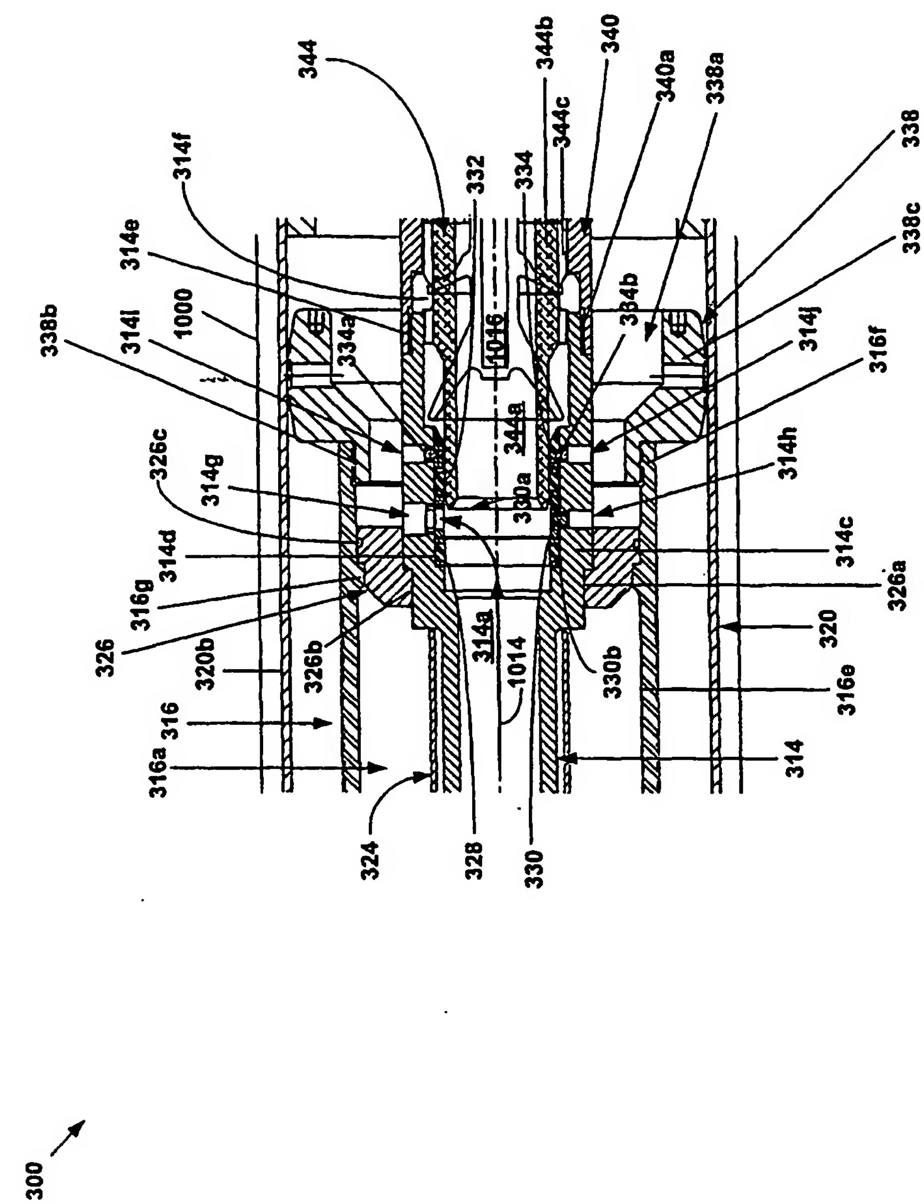

316f
344
338
344a
326c
314d
326a
314c
320b
316g
326
326b
316
316e
316a
1014
314
316h
324
318d
316j
316i
316c
314a
324a
316d
318c
318
324b
316b
318e
318a
320
322a
322
314b
312d
318b
1000
312b
312c
312
320a
1014
1002
320c
300
1004
1004

Fig. 27a


344
344b
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340a
338a
338
338c
314f
332
334
344c
314e
1000
314l
338b
334a
1016
334b
314j
316f
326c
314g
344a
330a
314h
314d
314c
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314
324
328
330
300

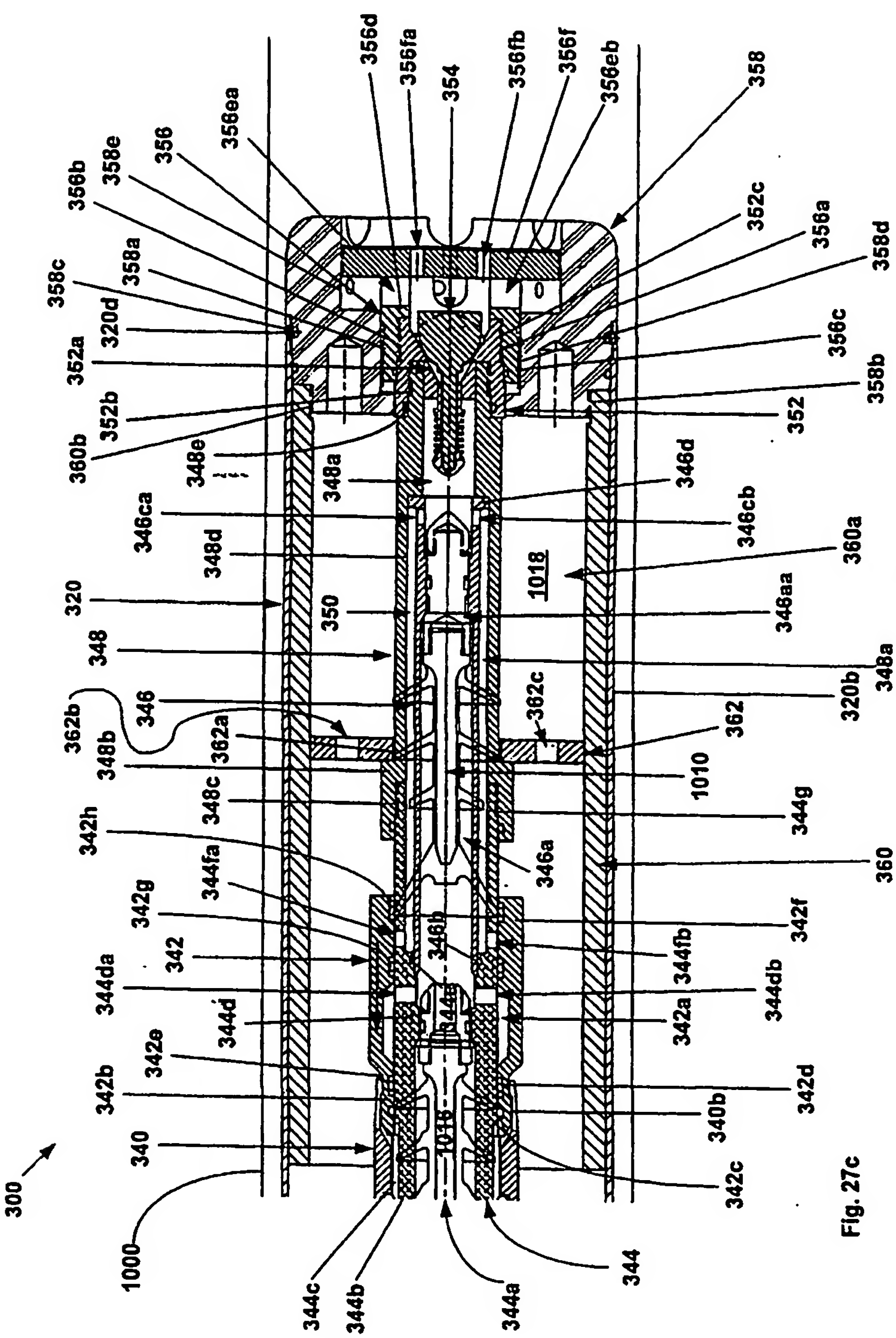


Fig. 27c

80/100

80/100

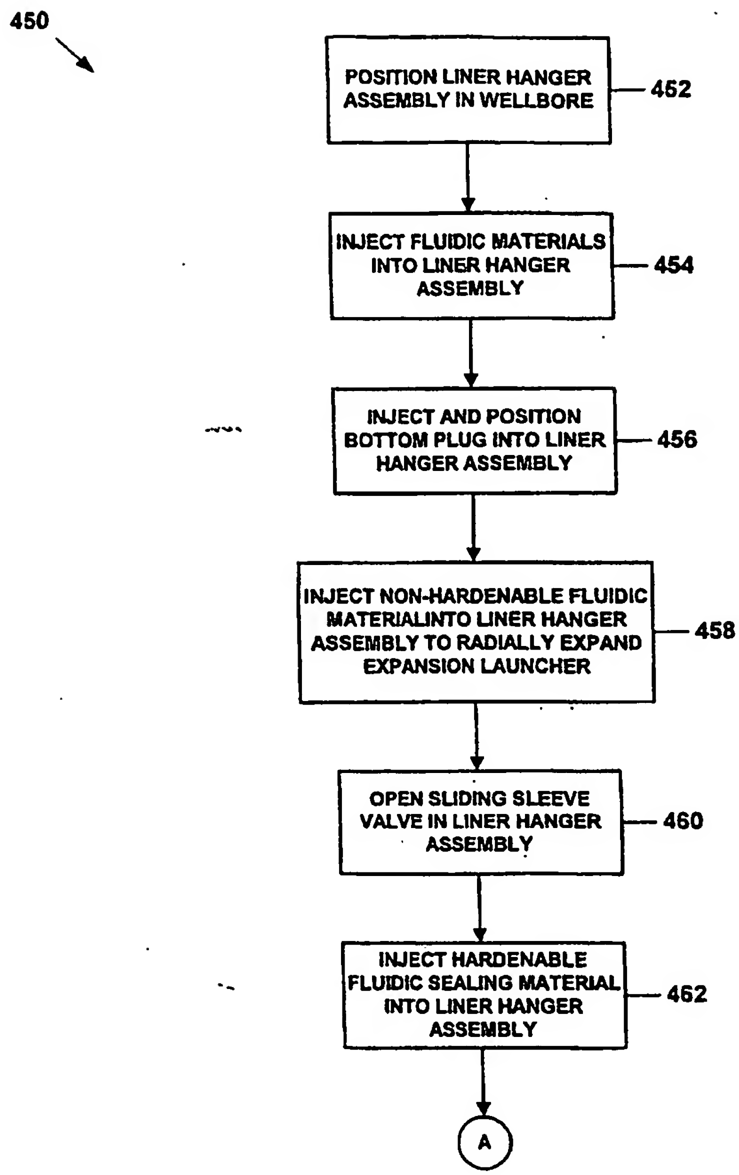

450
POSITION LINER HANGER ASSEMBLY IN WELLBORE
452
INJECT FLUIDIC MATERIALS INTO LINER HANGER ASSEMBLY
454
INJECT AND POSITION BOTTOM PLUG INTO LINER HANGER ASSEMBLY
456
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
458
OPEN SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
460
INJECT HARDENABLE FLUIDIC SEALING MATERIAL INTO LINER HANGER ASSEMBLY
462
A

Fig. 28a

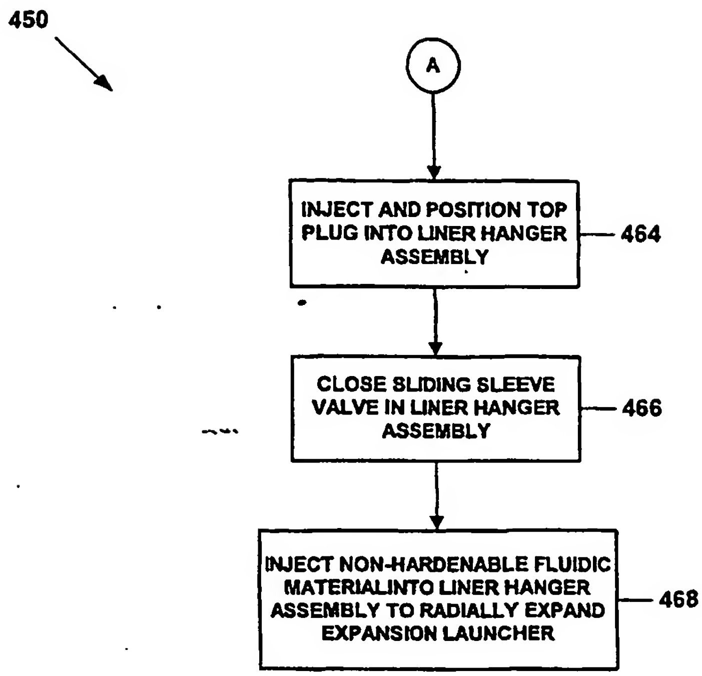

450
A
INJECT AND POSITION TOP PLUG INTO LINER HANGER ASSEMBLY
464
CLOSE SLIDING SLEEVE VALVE IN LINER HANGER ASSEMBLY
466
INJECT NON-HARDENABLE FLUIDIC MATERIALINTO LINER HANGER ASSEMBLY TO RADIALLY EXPAND EXPANSION LAUNCHER
468

Fig. 28b

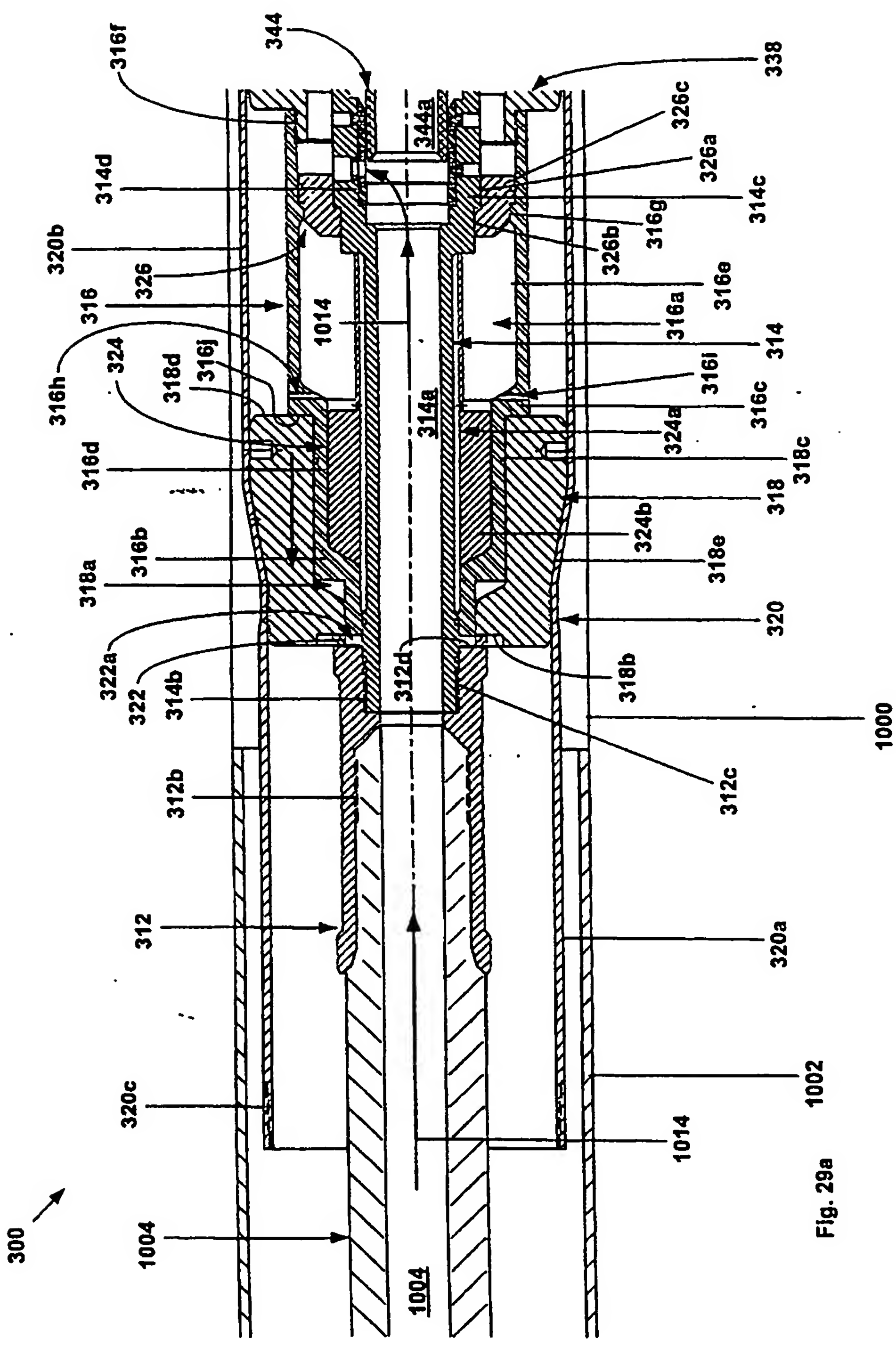
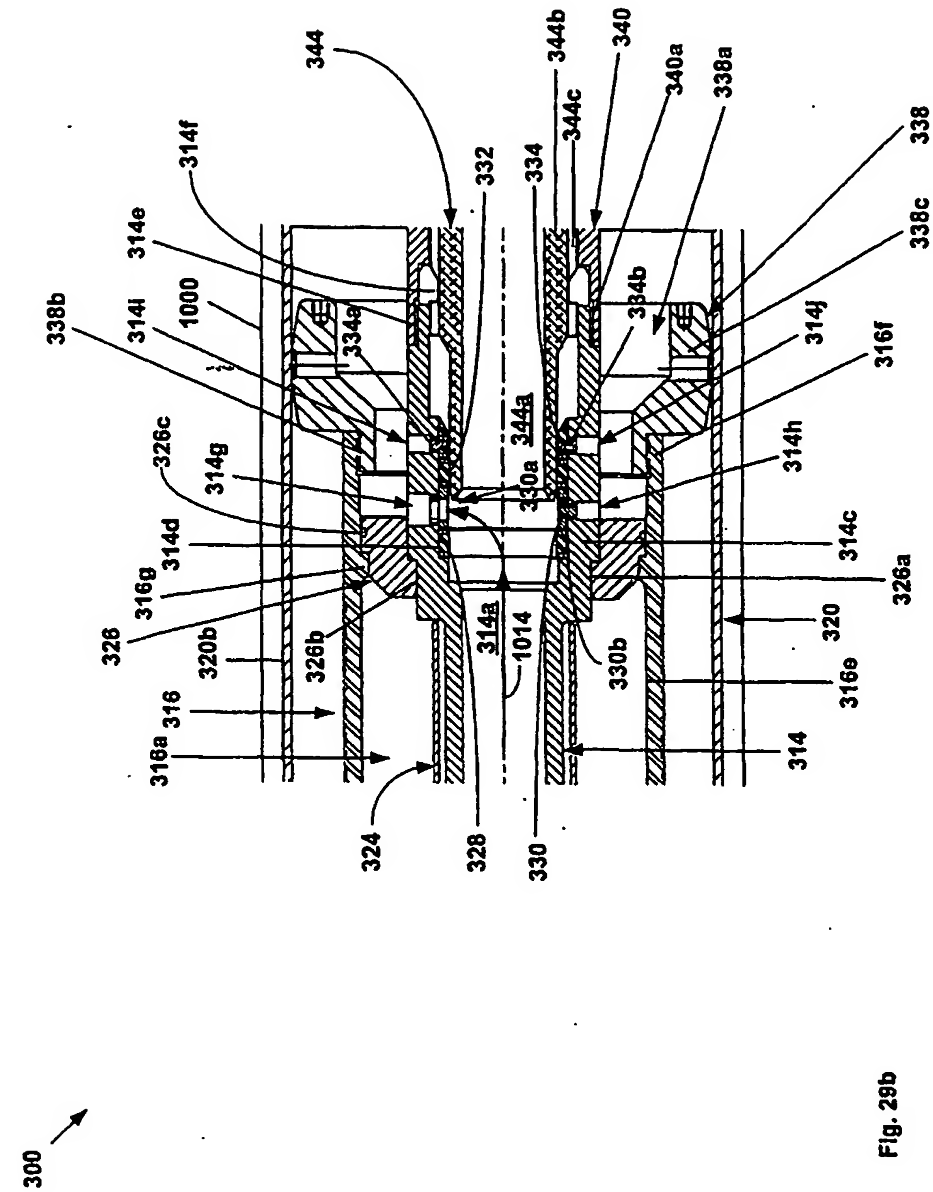

300
316f
344
344a
338
326c
326a
314d
314c
326b
316g
320b
326
316e
316
316a
1014
314
316h
324
318d
316j
316i
316c
314a
324a
316d
318c
318
324b
316b
318e
318a
320
322a
322
314b
312d
318b
1000
312c
312b
312
320a
320c
1002
1014
1004
1004

Fig. 29a


300
344
344b
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340a
338a
338
338c
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332
334
344c
314e
334b
314j
316f
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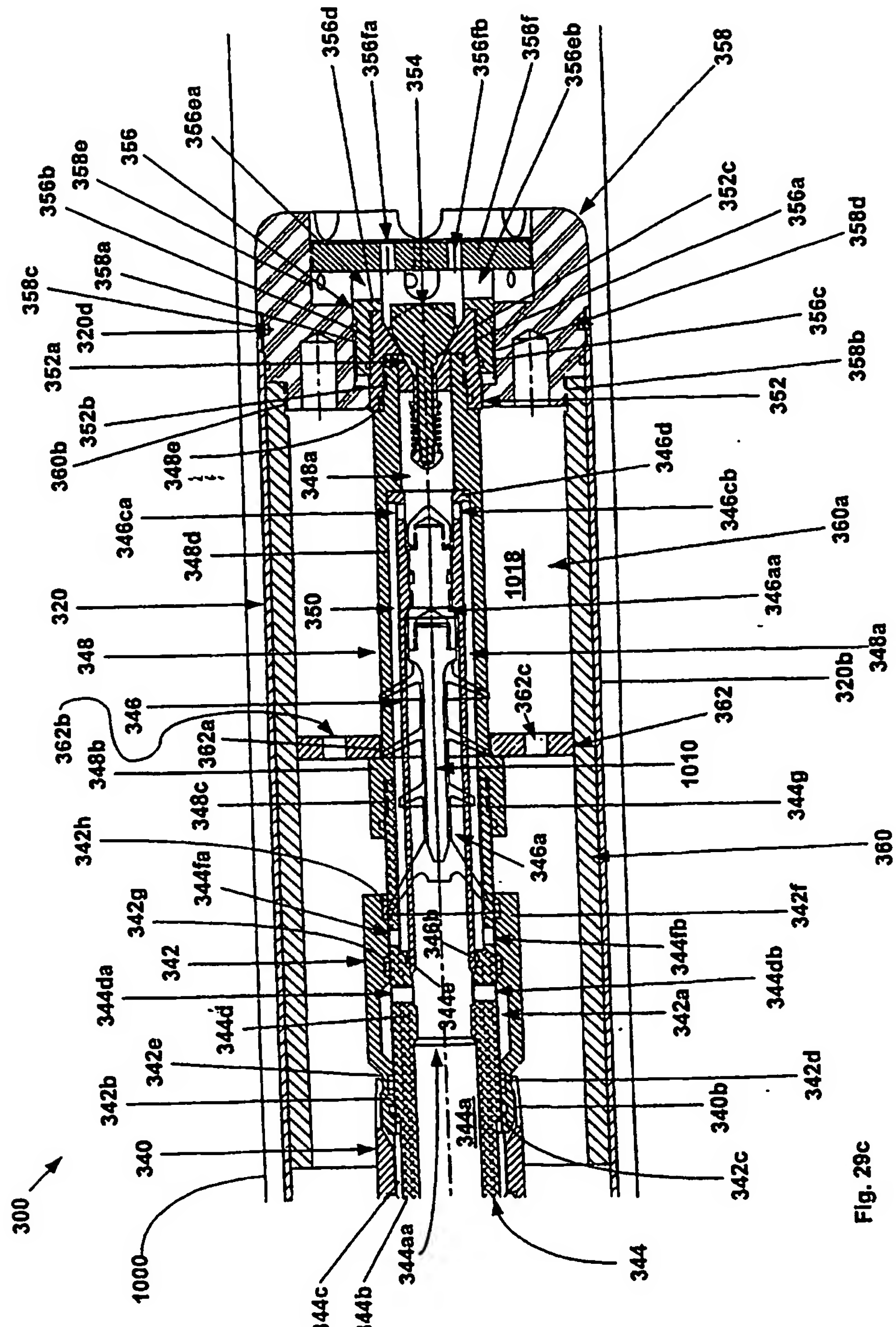
1000
334a
344a
314h
326c
314g
330a
314c
314d
326a
316g
326
320b
326b
314a
1014
330b
320
316e
316
316a
314
324
328
330

Fig. 29b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342b
342e
344d
344da
342
342g
344fa
342h
348c
348b
362b
362a
346
348
350
348d
346ca
320
348a
348e
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
1018
346aa
348a
320b
362c
362
1010
344g
346a
360
342f
346b
344fb
344e
344db
342a
342d
344a
340b
342c
344
344aa
344b
344c

Fig. 29c

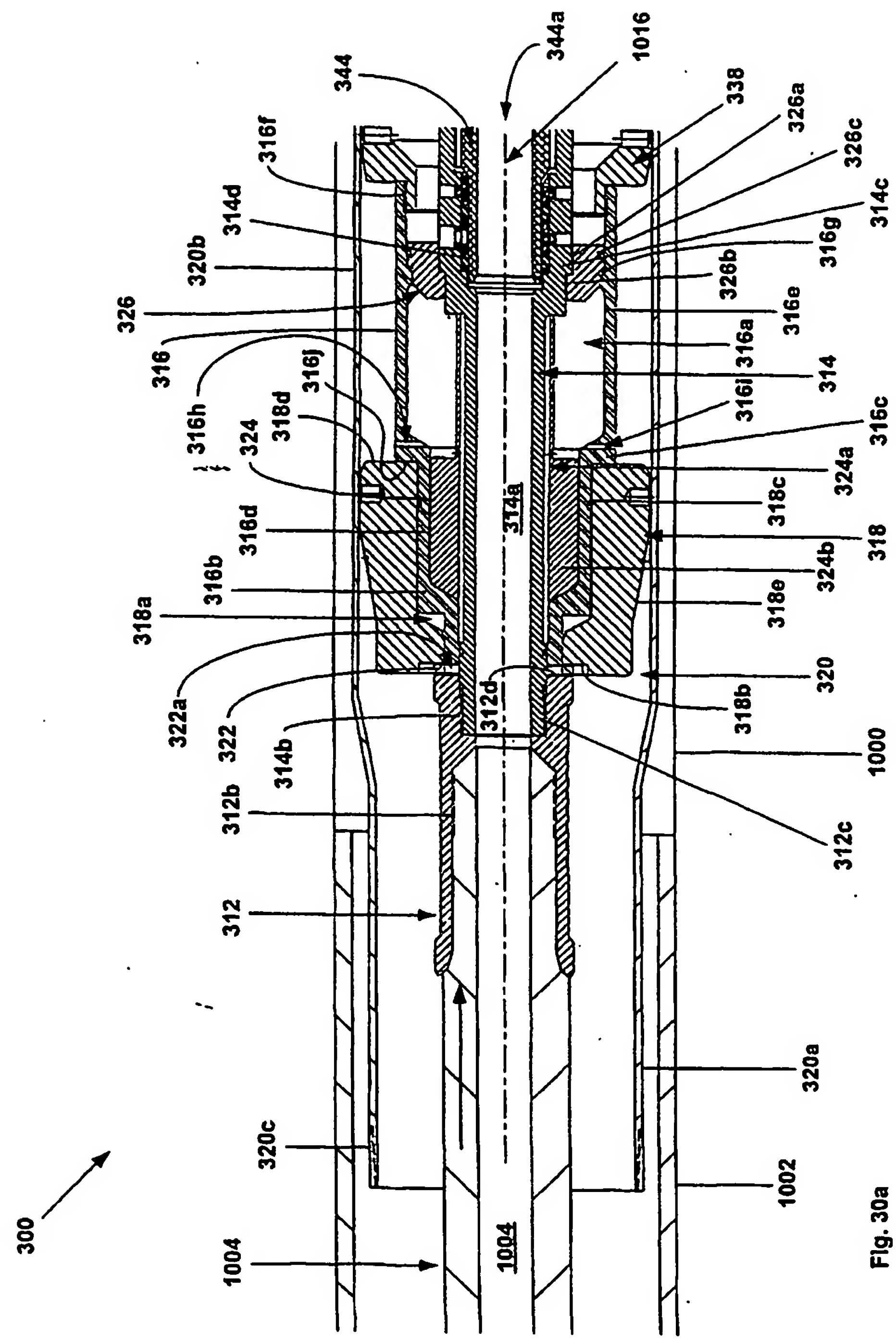
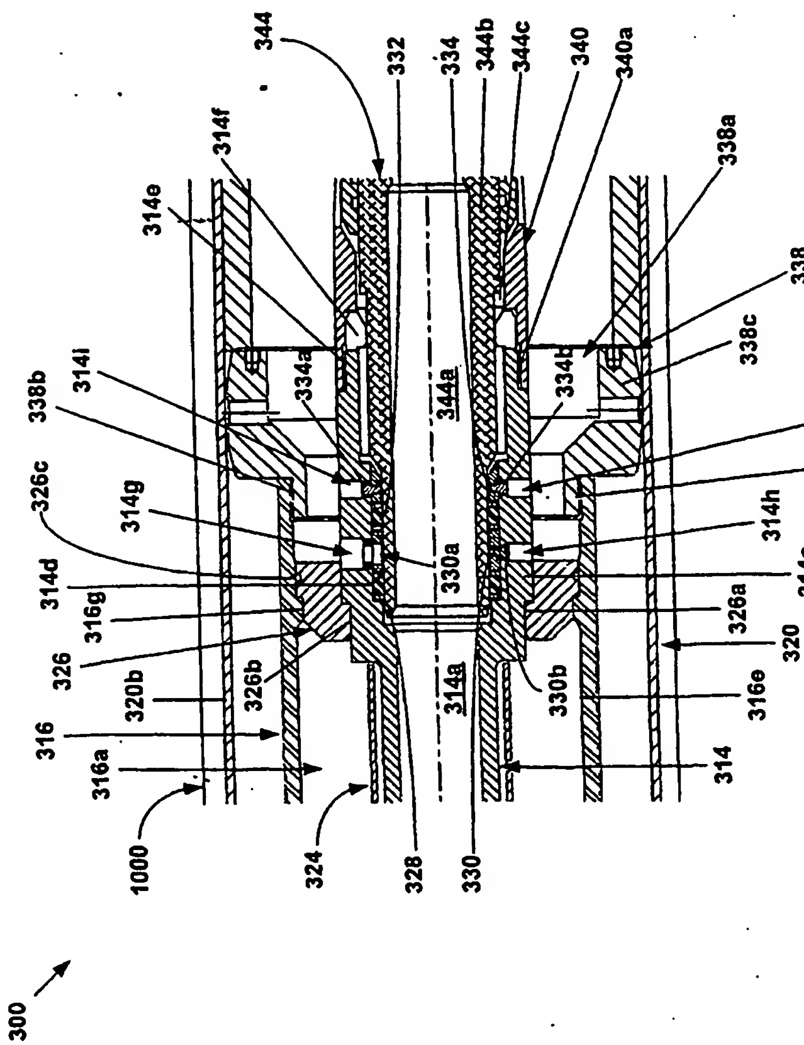

300
344
344a
1016
338
326a
326c
314c
316g
326b
316e
316a
314
316i
316c
324a
318c
318
324b
318e
320
318b
1000
312c
320a
1002
316f
314d
320b
326
316
316h
316j
318d
324
316d
316b
318a
322a
322
314b
312b
312
320c
1004
314a
312d

Fig. 30a


300
1000
316a
316
320b
326b
326
316g
314d
326c
314g
338b
314i
334a
314e
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334
344b
344c
340
340a
338a
338
338c
314j
316f
314h
314c
326a
320
316e
314
330b
314a
344a
334b
330a
324
328
330

Fig. 30b

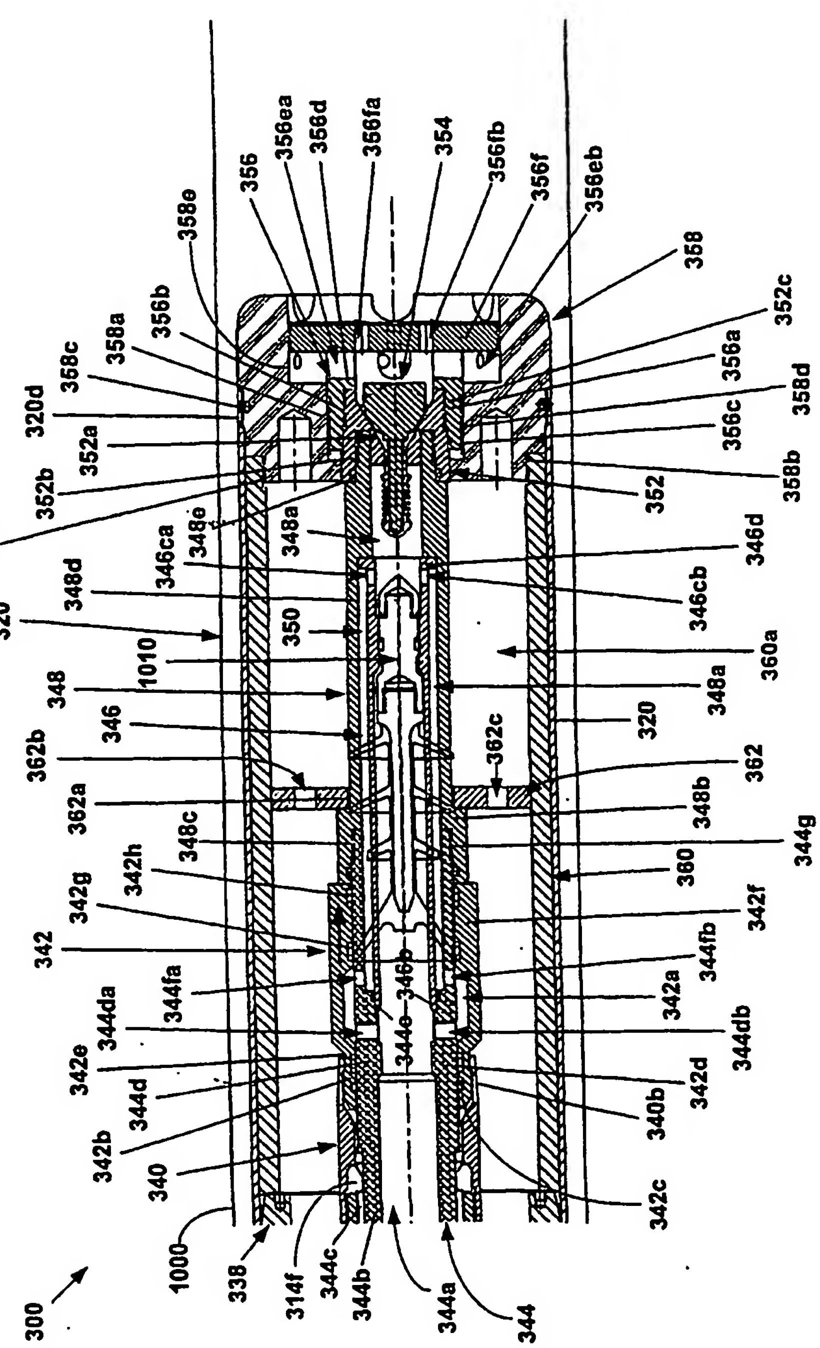

300
1000
338
314f
344c
344b
344a
344
340
342b
344d
342e
344da
344fa
344e
346b
342
342g
342h
348c
362a
362b
346
348
1010
350
348d
346ca
348e
348a
320
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
348a
320
362c
362
348b
344g
360
342f
344fb
342a
344db
342d
340b
342c

Fig. 30c

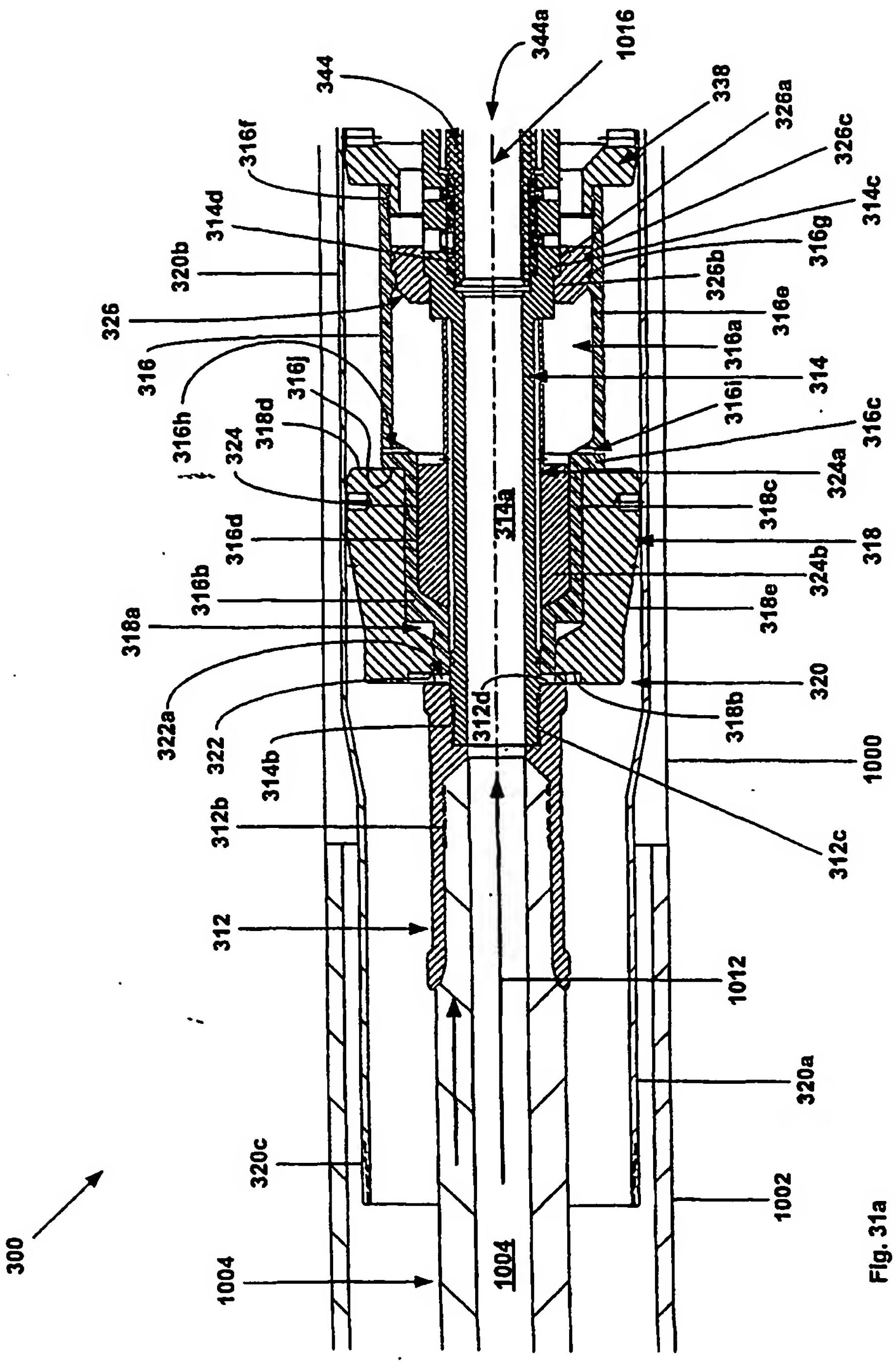
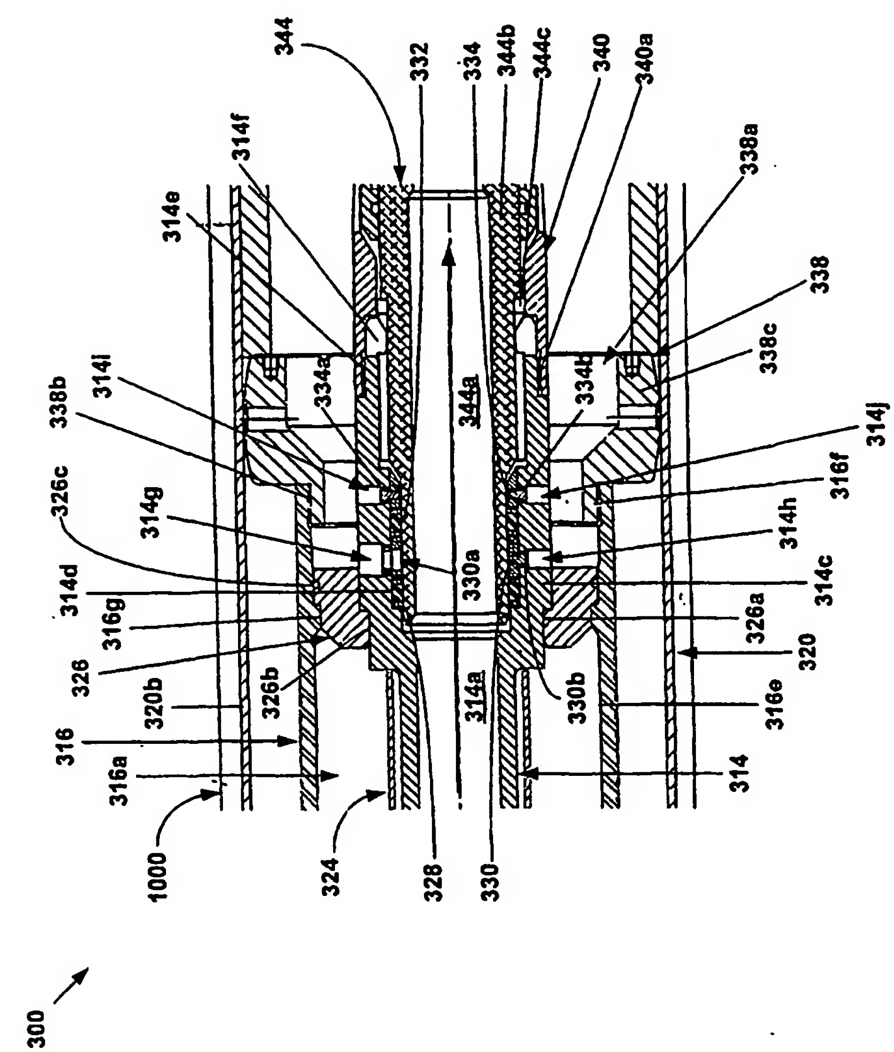

300
344
344a
1016
338
326a
326c
314c
316g
326b
316e
316a
314
316i
316c
324a
318c
318
324b
318e
320
318b
1000
312c
1012
320a
1002
316f
314d
320b
326
316
316h
316j
318d
324
316d
316b
318a
322a
322
314b
312d
314a
312b
312
320c
1004
1004

Fig. 31a



344
332
334
344b
344c
340
340a
314f
314e
338a
338
338c
338b
314l
334a
344a
334b
314j
316f
326c
314g
330a
314h
314d
316g
314c
326a
326
326b
320
320b
330b
316
316e
316a
314a
314
1000
324
328
330
300

Fig. 31b

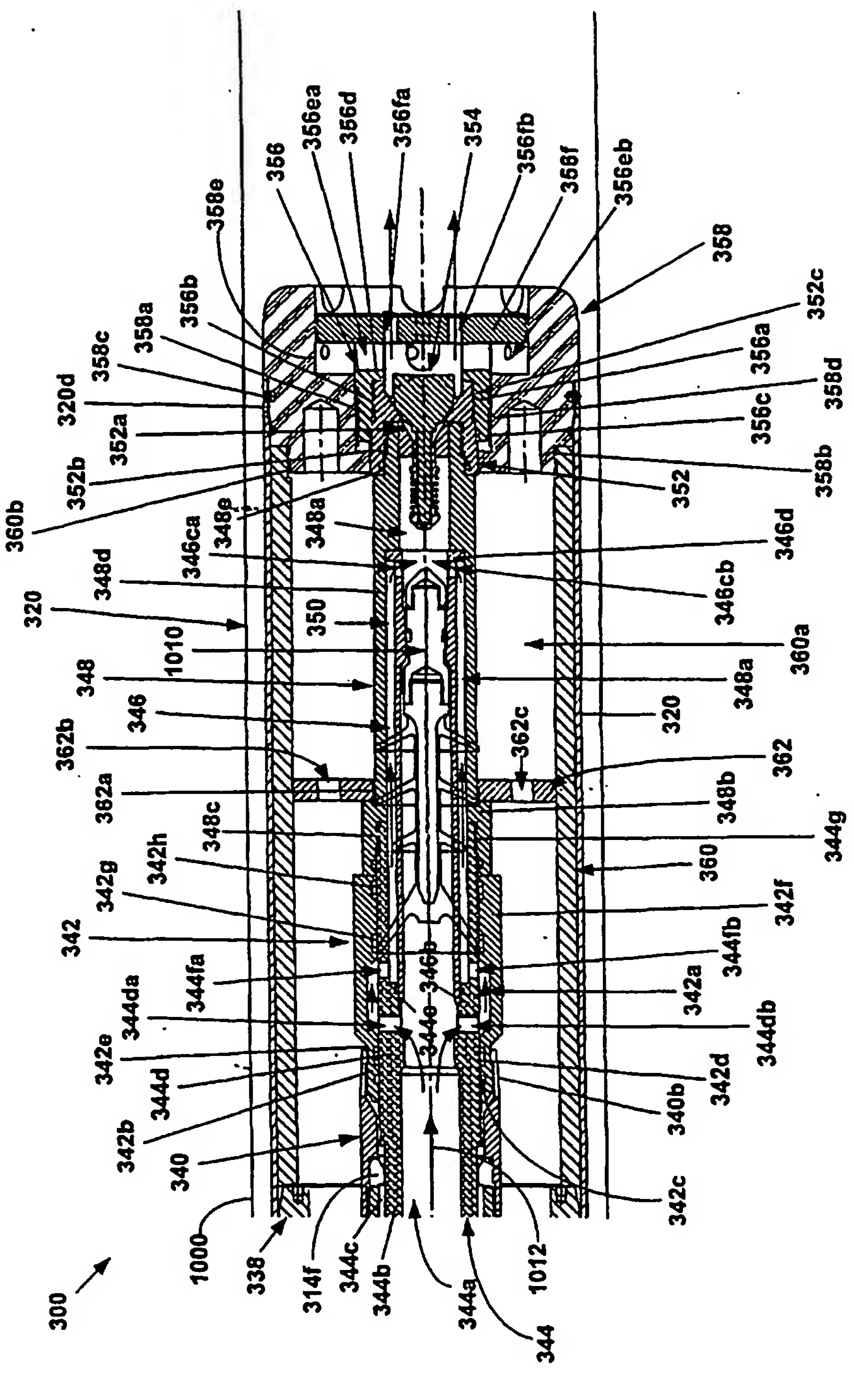

300
1000
338
314f
344c
344b
344a
1012
344
340
342b
344d
342e
344da
344fa
342
342g
342h
348c
362a
362b
346
348
1010
350
348d
346ca
348e
348a
320
360b
352b
352a
320d
358c
358a
356b
358e
356
356ea
356d
356fa
354
356fb
356f
356eb
358
352c
356a
358d
356c
358b
352
346d
346cb
360a
348a
320
362c
362
348b
344g
360
342f
344fb
342a
344db
342d
340b
342c
346b
344e

Fig. 31c

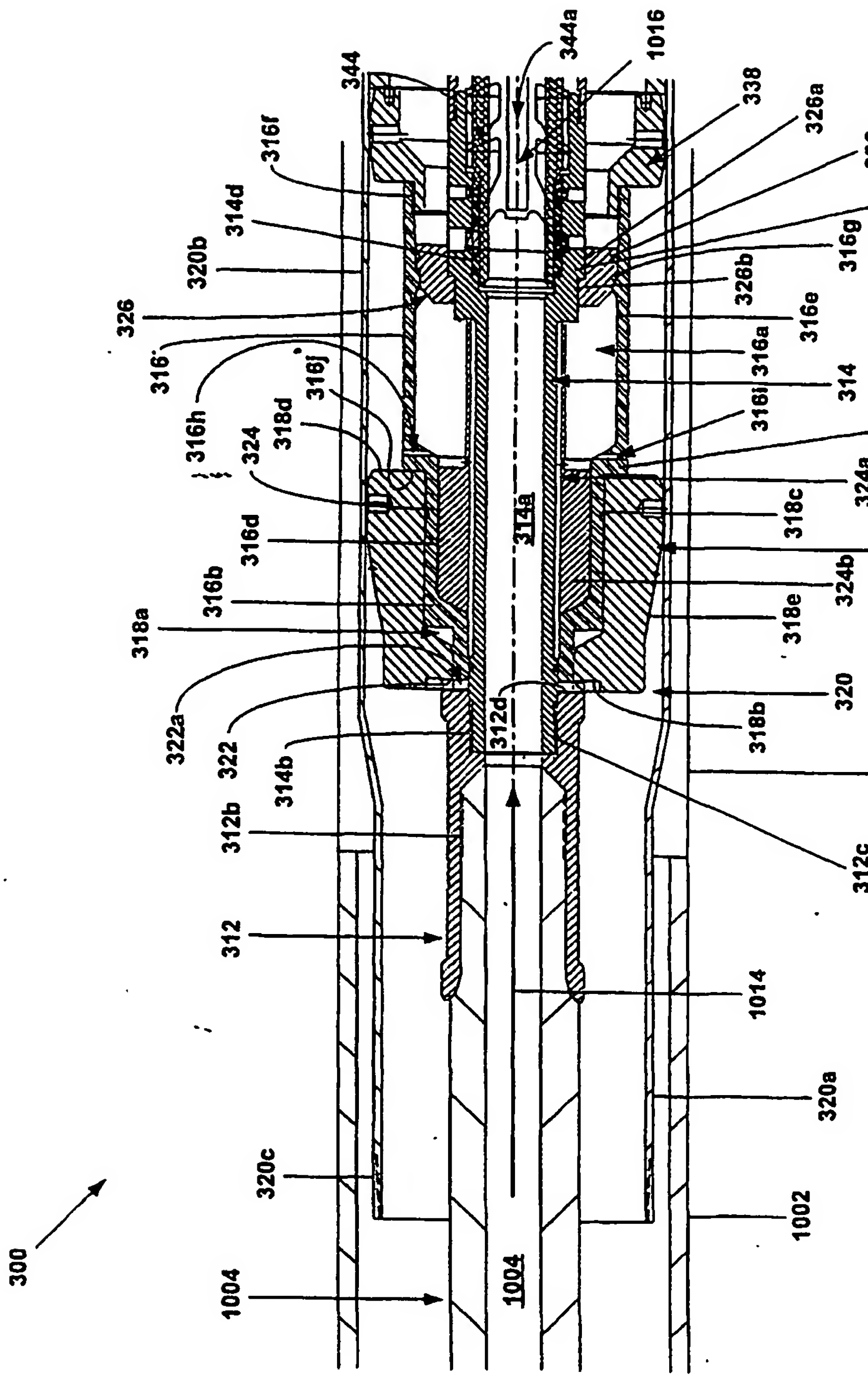

300
1004
1004
320c
312
312b
314b
322
322a
318a
316b
316d
324
316h
318d
316j
316
326
320b
314d
316f
344
344a
1016
338
326a
326c
314c
316g
326b
316e
316a
316i
314
316c
324a
318c
318
324b
318e
320
318b
312d
314a
1000
312c
1014
320a
1002

Fig. 32a

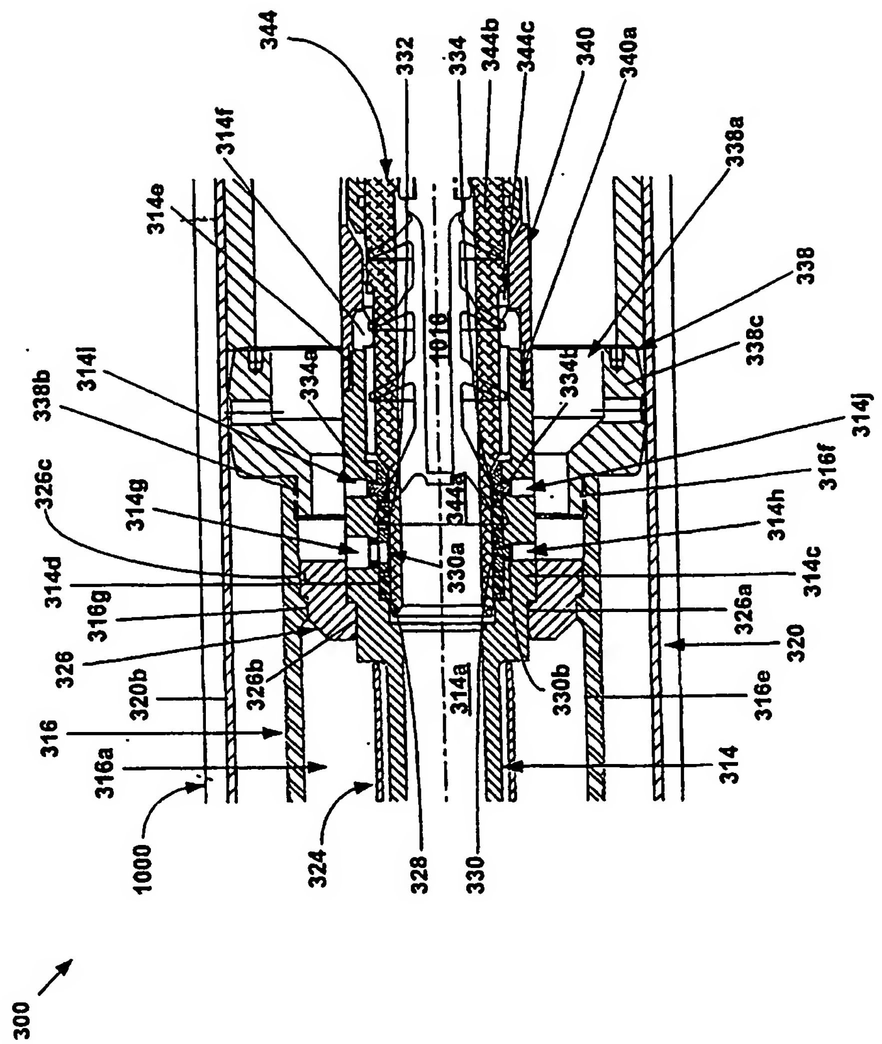

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Fig. 32b

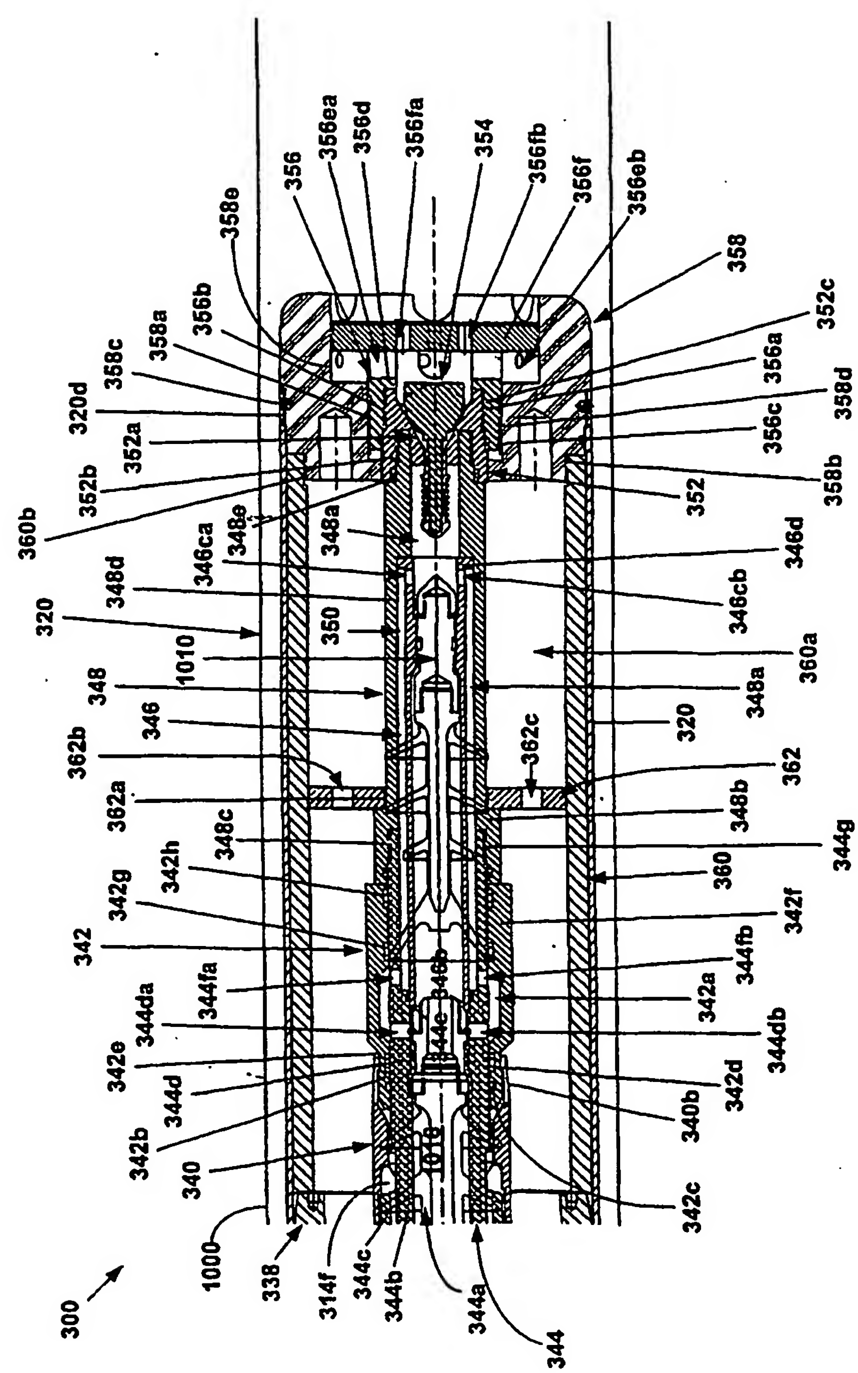
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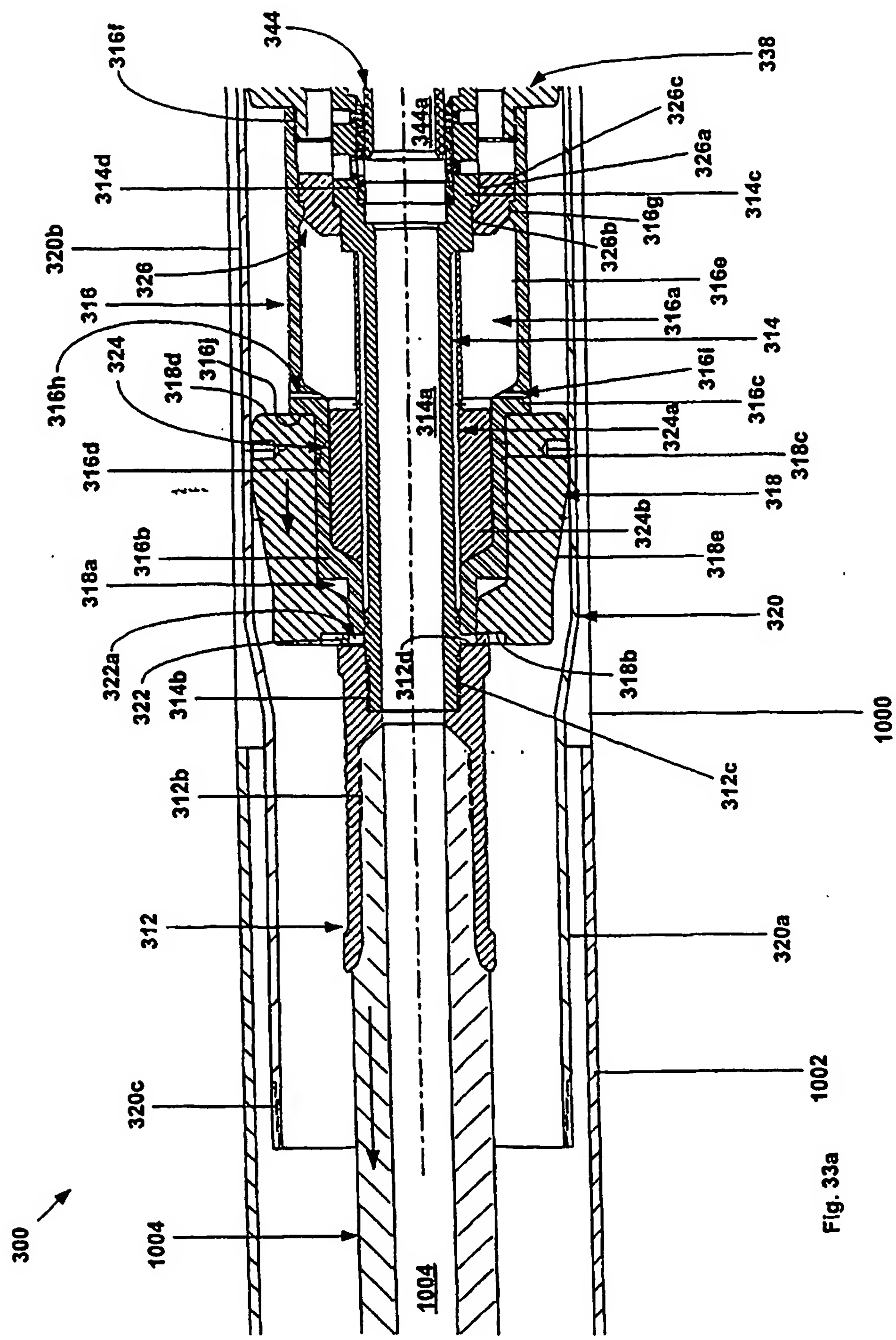
Fig. 32c



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316d
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324b
316b
318e
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Fig. 33a

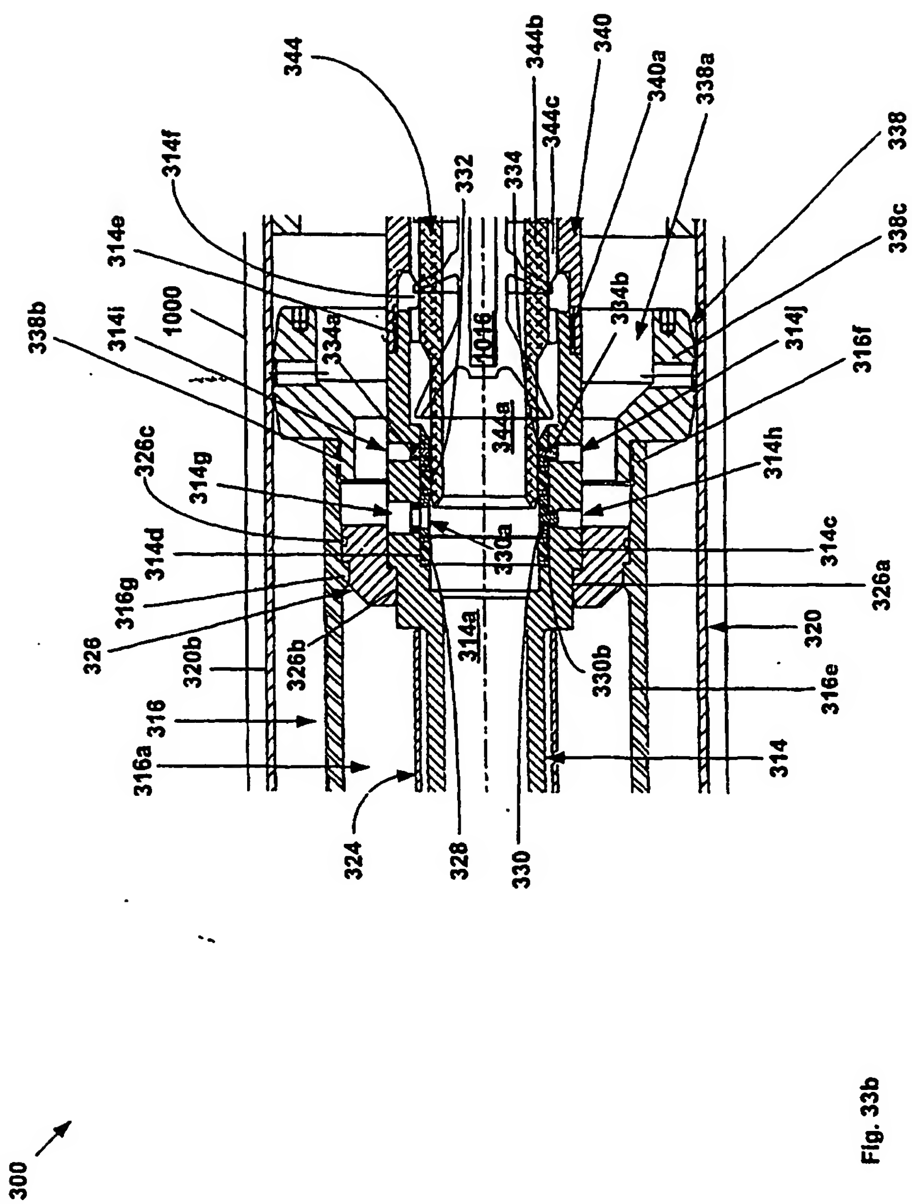
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Fig. 33b

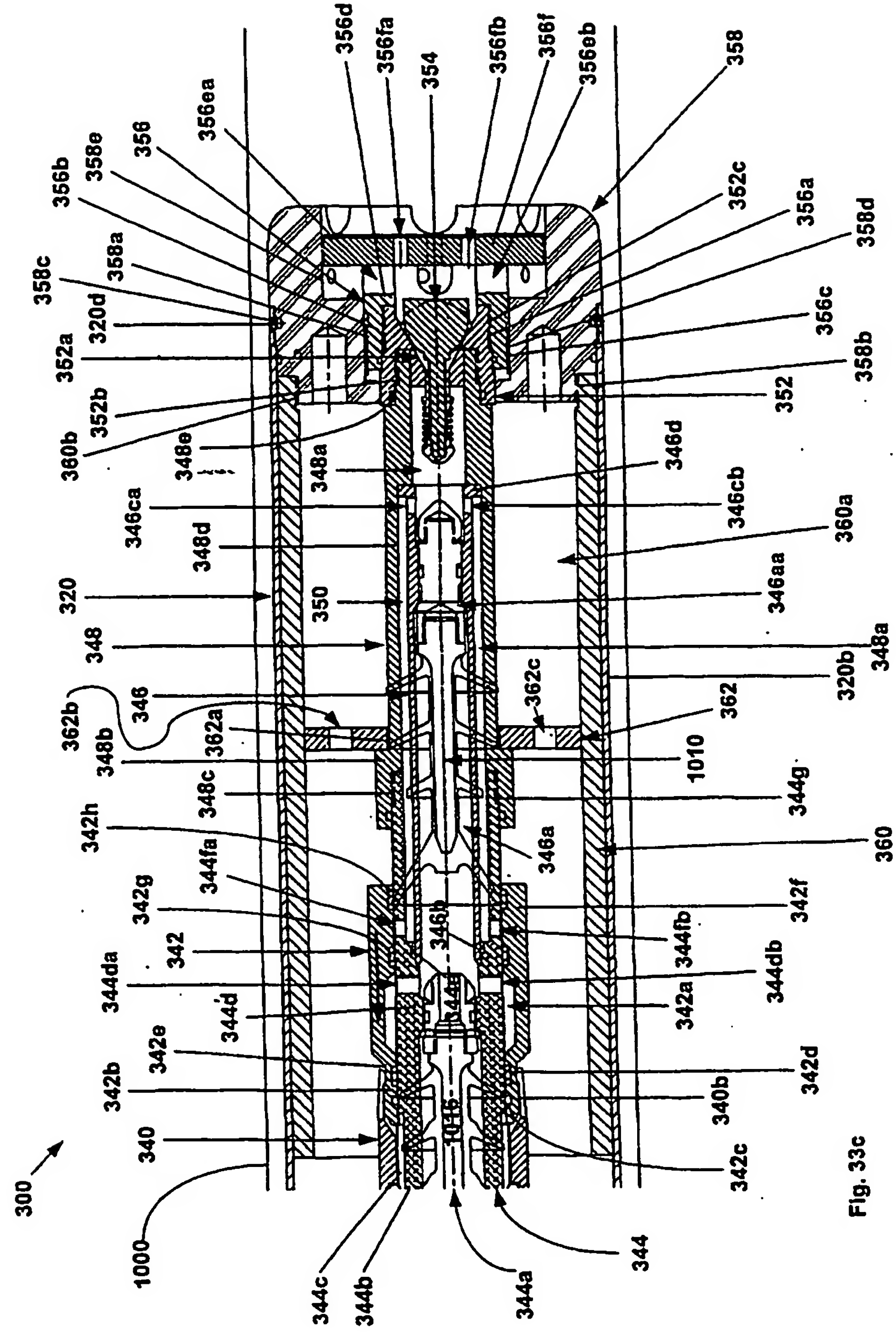
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Fig. 33c

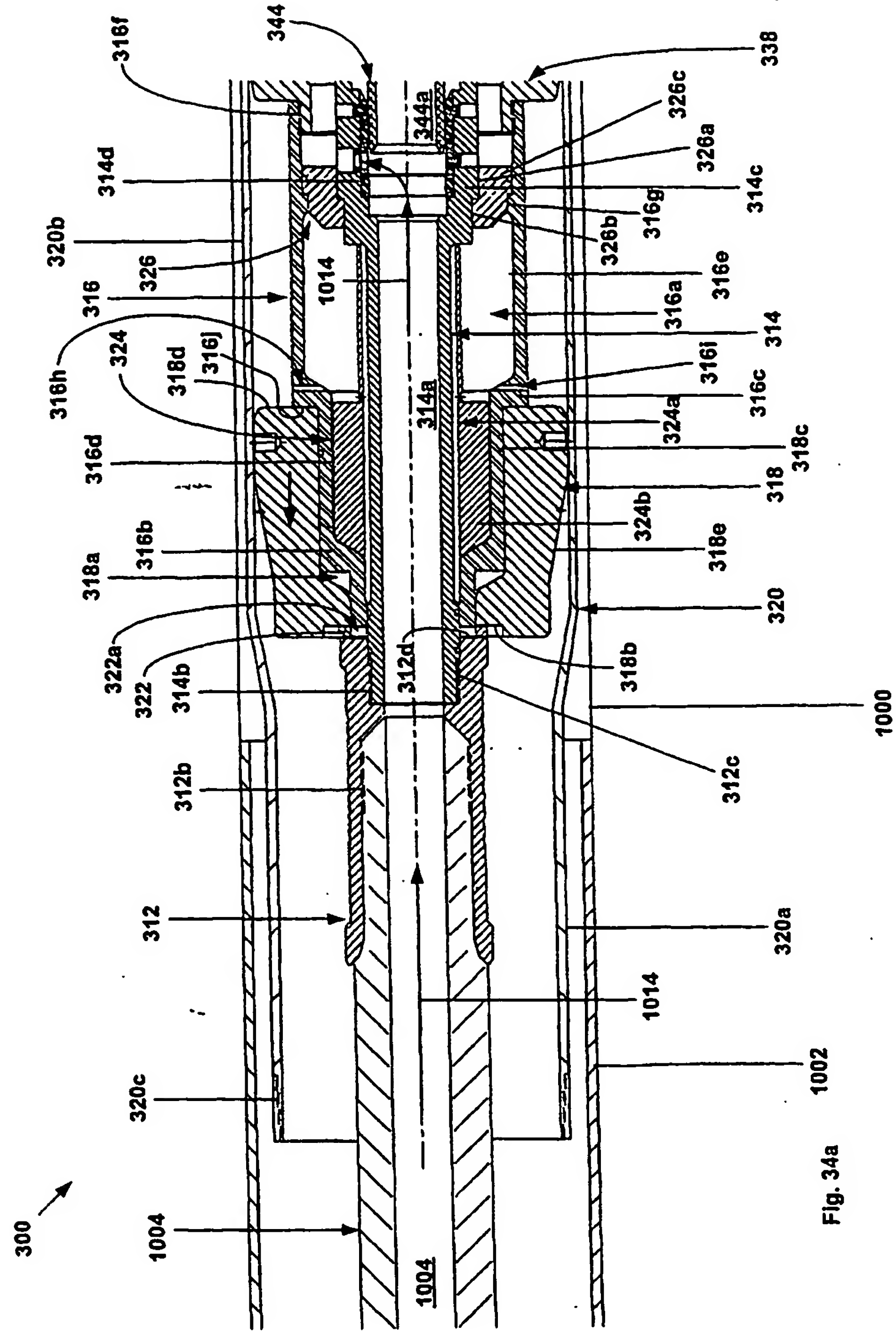
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Fig. 34a

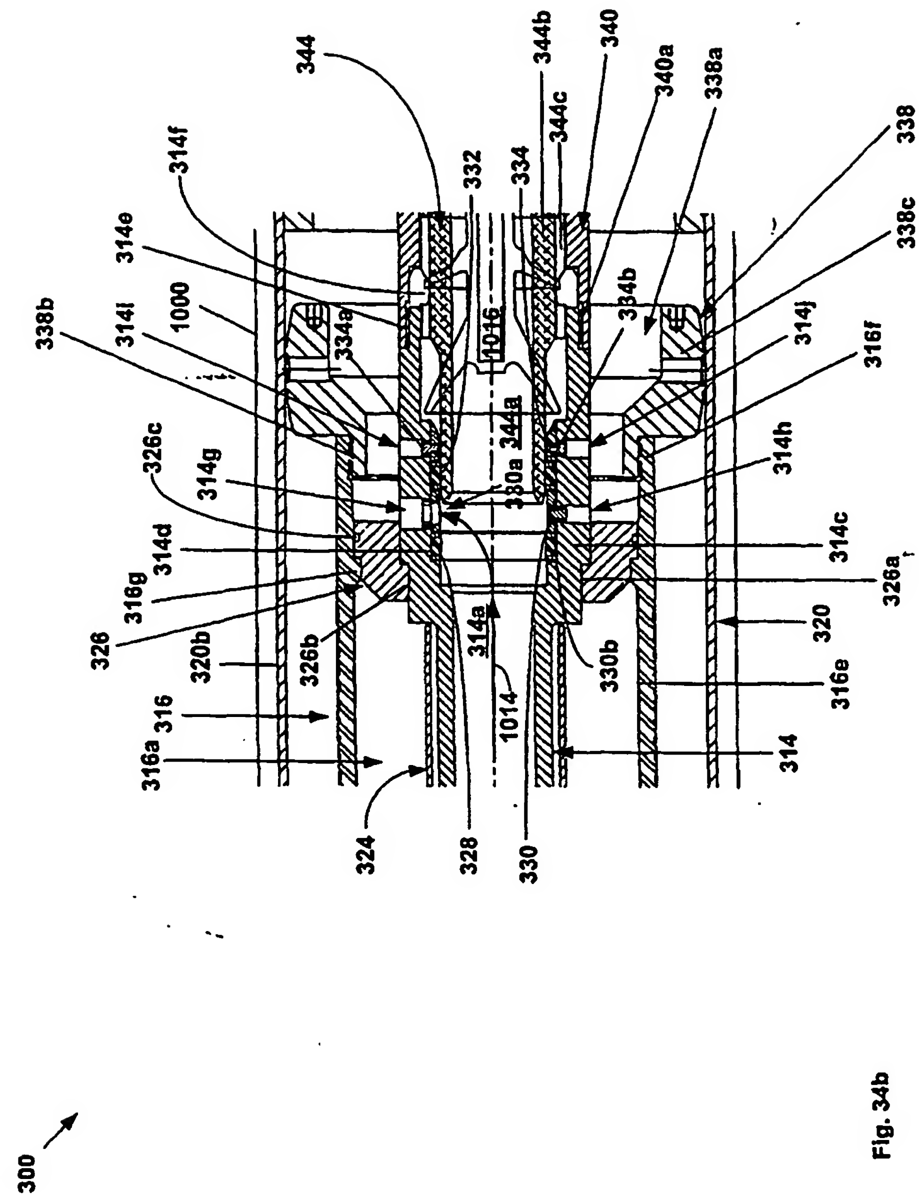
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Fig. 34b

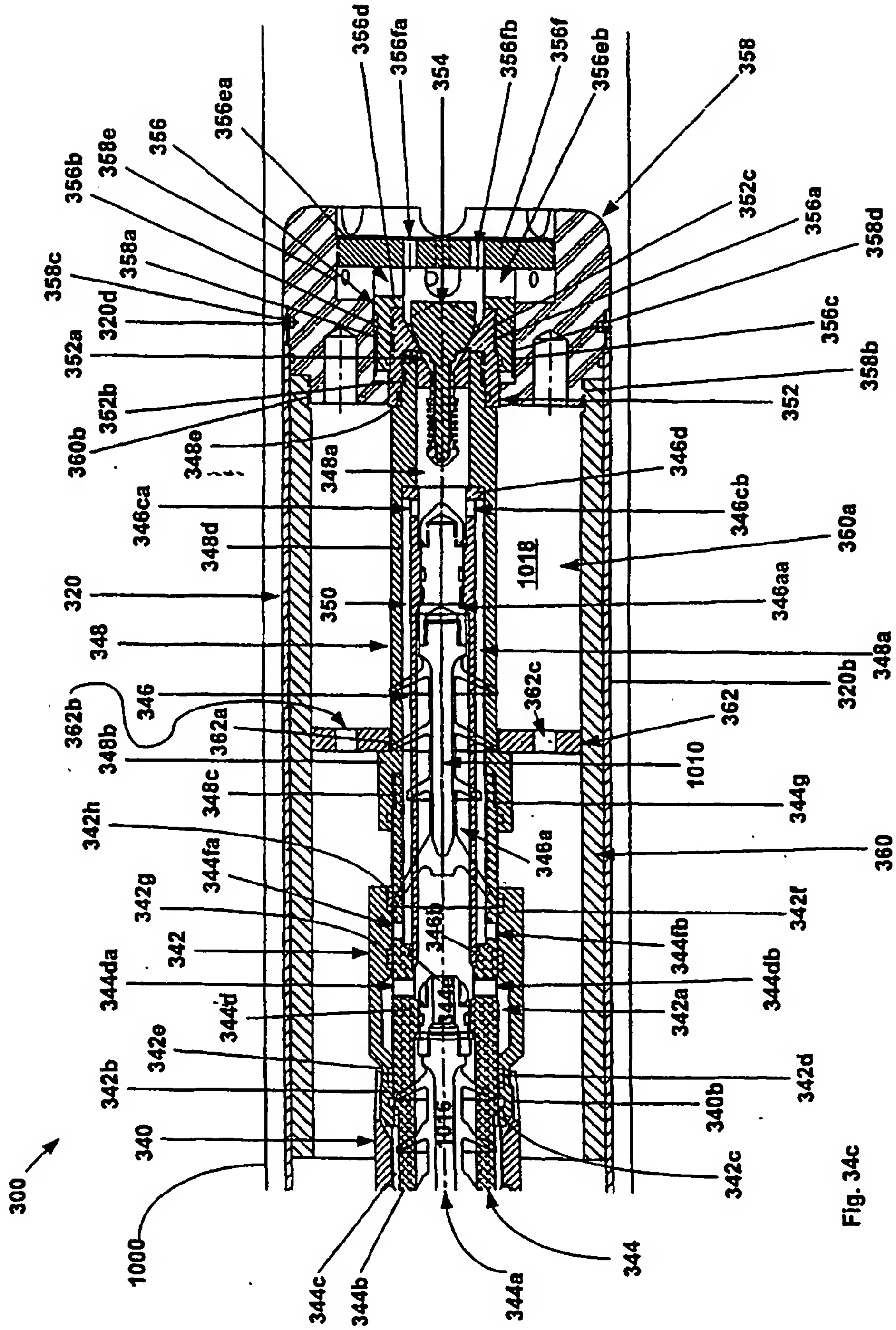
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Fig. 34c

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FORMING A WELLBORE CASING

Background of the Invention

This invention relates generally to forming wellbore casings.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores.

Summary of the Invention

According to one aspect of the present invention there is provided an apparatus for forming a wellbore casing within a borehole within a subterranean formation, comprising:

a first annular support member defining a first fluid passage and one or more first radial passages each having one or more pressure sensitive valves fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having first and second throat passages, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve.

According to another aspect of the present invention there is provided a method of operating an apparatus for forming a wellbore casing within a borehole within a subterranean formation, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages and having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the borehole;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand the expandable tubular member.

Preferably, positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the borehole.

Preferably, the method further comprises: positioning a top plug in the top throat passage.

According to another aspect of the present invention there is provided a method of operating an apparatus for forming a wellbore casing within a borehole within a subterranean formation, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the borehole;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

injecting a non-hardenable fluidic material through the first fluid passages and the first radial passages and pressure sensitive valves into the annular region to radially expand a portion of the expandable tubular member;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand another portion of the expandable tubular member.

Preferably, positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the borehole.

Preferably, positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to a preexisting section of wellbore casing within the borehole.

Preferably, injecting a non-hardenable fluidic material into the first fluid passage and one or more first radial passages and pressure sensitive valves to radially expand a portion of the expandable tubular member comprises:

injecting a non-hardenable fluidic material into the first fluid passage and the one or more first radial passages and pressure sensitive valves to radially expand the expandable tubular member until an end portion of the tubular member is positioned proximate the bottom of the borehole.

Preferably, the method further comprises positioning a top plug in the top throat passage.

According to another aspect of the present invention there is provided an apparatus for coupling an expandable tubular member to a preexisting structure, comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having first and second throat passages, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled

to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve.

According to another aspect of the present invention there is provided a method of operating an apparatus for coupling an expandable tubular member to a preexisting structure, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the preexisting structure;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand the expandable tubular member.

Preferably, positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the preexisting structure.

Preferably, the method further comprises positioning a top plug in the top throat passage.

According to another aspect of the present invention there is provided a method of operating an apparatus for coupling an expandable tubular member to a preexisting structure, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining

second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the preexisting structure;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

injecting a non-hardenable fluidic material through the first fluid passages and the first radial passages and pressure sensitive valves into the annular region to radially expand a portion of the expandable tubular member;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand another portion of the expandable tubular member.

Preferably, positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the preexisting structure.

Preferably, positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to a preexisting section of a structural element within the preexisting structure.

Preferably, injecting a non-hardenable fluidic material into the first fluid passage and the one or more first radial passages and pressure sensitive valves to radially expand a portion of the expandable tubular member comprises:

injecting a non-hardenable fluidic material into the first fluid passage and one or more first radial passages and pressure sensitive valves to radially expand the expandable tubular member until an end portion of the tubular member is positioned proximate the bottom of the preexisting structure.

Preferably, the method further comprises positioning a top plug in the top throat passage.

Brief Description of the Drawings

Figs. 1 and 1a-1c are cross sectional illustrations of a liner hanger assembly including a sliding sleeve valve assembly.

Figs. 2a-2b is a flow chart illustration of a method for forming a wellbore casing using the liner hanger assembly of Figs. 1 and 1a-1c.

Figs. 3a-3c are cross sectional illustrations of the placement of the liner hanger assembly of Figs. 1 and 1a-1c into a wellbore.

Figs. 4a-4c are cross sectional illustrations of the injection of fluidic materials into the liner hanger assembly of Figs. 3a-3c.

Figs. 5a-5c are cross sectional illustrations of the placement of a bottom plug into the liner hanger assembly of Figs. 4a-4c.

Figs. 6a-6c are cross sectional illustrations of the downward displacement of sliding sleeve of the liner hanger assembly of Figs. 5a-5c.

Figs. 7a-7c are cross sectional illustrations of the injection of a hardenable fluidic sealing material into the liner hanger assembly of Figs. 6a-6c that bypasses the plug.

Figs. 8a-8c are cross sectional illustrations of the placement of a top plug into the liner hanger assembly of Figs. 7a-7c.

Figs. 9a-9c are cross sectional illustrations of the upward displacement of sliding sleeve of the liner hanger assembly of Figs. 8a-8c.

Figs. 10a-10c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 9a-9c in order to radially expand and plastically deform the expansion cone launcher.

Figs. 11a-11b is a flow chart illustration of a method for forming a wellbore casing using the liner hanger assembly of Figs. 1 and 1a-1c.

Figs. 12a-12c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 5a-5c in order to at least partially radially expand and plastically deform the expansion cone launcher.

Figs. 13a-13c are cross sectional illustrations of the downward displacement of the sliding sleeve of the liner hanger assembly of Figs. 12a-12c.

Figs. 14a-14c are cross sectional illustrations of the injection of a hardenable fluidic sealing material through the liner hanger assembly of Figs. 13a-13c.

Figs. 15a-15c are cross sectional illustrations of the injection and placement of a top plug into the liner hanger assembly of Figs. 14a-14c.

Figs. 16a-16c are cross sectional illustrations of the upward displacement of the sliding sleeve of the liner hanger assembly of Figs. 15a-15c.

Figs. 17a-17c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 16a-16c in order to complete the radial expansion of the expansion cone launcher.

Figs. 18, 18a, 18b, and 18c are cross sectional illustrations of a liner hanger assembly including a sliding sleeve valve assembly.

Figs. 19a-19b is a flow chart illustration of a method for forming a wellbore casing using the liner hanger assembly of Figs. 18 and 18a-18c.

Figs. 20a-20c are cross sectional illustrations of the placement of the liner hanger assembly of Figs. 18 and 18a-18c into a wellbore.

Figs. 21a-21c are cross sectional illustrations of the injection of a fluidic materials into the liner hanger assembly of Figs. 20a-20c.

Figs. 22a-22c are cross sectional illustrations of the placement of a bottom plug into the liner hanger assembly of Figs. 21a-21c.

Figs. 23a-23c are cross sectional illustrations of the downward displacement of sliding sleeve of the liner hanger assembly of Figs. 22a-22c.

Figs. 24a-24c are cross sectional illustrations of the injection of a hardenable fluidic sealing material into the liner hanger assembly of Figs. 23a-23c that bypasses the bottom plug.

Figs. 25a-25c are cross sectional illustrations of the placement of a top plug into the liner hanger assembly of Figs. 24a-24c.

Figs. 26a-26c are cross sectional illustrations of the upward displacement of sliding sleeve of the liner hanger assembly of Figs. 25a-25c.

Figs. 27a-27c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 26a-26c in order to radially expand and plastically deform the expansion cone launcher.

Figs. 28a-28b is a flow chart illustration of a method for forming a wellbore casing using the liner hanger assembly of Figs. 18 and 18a-18c.

Figs. 29a-29c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 22a-22c in order to at least partially radially expand and plastically deform the expansion cone launcher.

Figs. 30a-30c are cross sectional illustrations of the downward displacement of the sliding sleeve of the liner hanger assembly of Figs. 29a-29c.

Figs. 31a-31c are cross sectional illustrations of the injection of a hardenable fluidic sealing material through the liner hanger assembly of Figs. 30a-30c.

Figs. 32a-32c are cross sectional illustrations of the injection and placement of a top plug into the liner hanger assembly of Figs. 31a-31c.

Figs. 33a-33c are cross sectional illustrations of the upward displacement of the sliding sleeve of the liner hanger assembly of Figs. 32a-32c.

Figs. 34a-34c are cross sectional illustrations of the injection of a pressurized fluidic material into the liner hanger assembly of Figs. 33a-33c in order to complete the radial expansion of the expansion cone launcher.

Detailed Description

A liner hanger assembly having a sliding sleeve bypass valve is provided. The liner hanger assembly provides a method and apparatus for forming or repairing a wellbore casing, a pipeline or a structural support.

Referring initially to Figs. 1, 1a, 1b, and 1c, a liner hanger assembly 10 includes a first tubular support member 12 defining an internal passage 12a that includes a threaded counterbore 12b at one end, and a threaded counterbore 12c at another end. A second tubular support member 14 defining an internal passage 14a includes a first threaded portion 14b at a first end that is coupled to the threaded counterbore 12c of the first tubular support member 12, a stepped flange 14c, a counterbore 14d, a threaded portion 14e, and internal splines 14f at another end. The stepped flange 14c of the second tubular support member 14 further defines radial passages 14g, 14h, 14i, and 14j. A third tubular support member 16 defining an internal passage 16a for receiving the second tubular support member 14 includes a first flange 16b, a second flange 16c, a first counterbore 16d, a second counterbore 16e having an internally threaded portion 16f, and an internal flange 16g. The second flange 16c further includes radial passages 16h and 16i.

An annular expansion cone 18 defining an internal passage 18a for receiving the second and third tubular support members, 14 and 16, includes a counterbore 18b at one end, and a counterbore 18c at another end for receiving the flange 16b of the second tubular support member 16. The annular expansion cone 18 further includes an end face 18d that mates with an end face 16j of the flange 16c of the second tubular support member 16, and an exterior surface 18e having a conical shape in order to facilitate the radial expansion of tubular members. A tubular expansion cone launcher 20 is movably coupled to the exterior surface 18e of the expansion cone 18 and includes a first portion 20a having a first wall thickness, a

second portion 20b having a second wall thickness, a threaded portion 20c at one end, and a threaded portion 20d at another end. The second portion 20b of the expansion cone launcher 20 mates with the conical outer surface 18e of the expansion cone 18. The second wall thickness is less than the first wall thickness in order to optimize the radial expansion of the expansion cone launcher 20 by the relative axial displacement of the expansion cone 18. One or more expandable tubulars are coupled to the threaded connection 20c of the expansion cone launcher 20. In this manner, the assembly 10 may be used to radially expand and plastically deform, for example, thousands of feet of expandable tubulars.

An annular spacer 22 defining an internal passage 22a for receiving the second tubular support member 14 is received within the counterbore 18b of the expansion cone 18, and is positioned between an end face 12d of the first tubular support member 12 and an end face of the counterbore 18b of the expansion cone 18. A fourth tubular support member 24 defining an internal passage 24a for receiving the second tubular support member 14 includes a flange 24b that is received within the counterbore 16d of the third tubular support member 16. A fifth tubular support member 26 defining an internal passage 26a for receiving the second tubular support member 14 includes an internal flange 26b for mating with the flange 14c of the second tubular support member and a flange 26c for mating with the internal flange 16g of the third tubular support member 16.

An annular sealing member 28, an annular sealing and support member 30, an annular sealing member 32, and an annular sealing and support member 34 are received within the counterbore 14d of the second tubular support member 14. The annular sealing and support member 30 further includes a radial opening 30a for supporting a rupture disc 36 within the radial opening 14g of the second tubular support member 14 and a sealing member 30b for sealing the radial opening 14h of the second tubular support member. The annular sealing and support member 34 further includes sealing members 34a and 34b for sealing the radial openings 14i and 14j, respectively, of the second tubular support member 14. The rupture disc 36 opens when the operating pressure within the radial opening 30b is about 6,894.745

to 34,473.724 KPa (1000 to 5000 psi). In this manner, the rupture disc 36 provides a pressure sensitive valve for controlling the flow of fluidic materials through the radial opening 30a. Alternatively, the assembly 10 includes a plurality of radial passages 30a, each with corresponding rupture discs 36.

A sixth tubular support member 38 defining an internal passage 38a for receiving the second tubular support member 14 includes a threaded portion 38b at one end that is coupled to the threaded portion 16f of the third tubular support member 16 and a flange 38c at another end that is movably coupled to the interior of the expansion cone launcher 20. An annular collet 40 includes a threaded portion 40a that is coupled to the threaded portion 14e of the second tubular support member 14, and a resilient coupling 40b at another end.

An annular sliding sleeve 42 defining an internal passage 42a includes an internal flange 42b, having sealing members 42c and 42d, and an external groove 42e for releasably engaging the coupling 40b of the collet 40 at one end, and an internal flange 42f, having sealing members 42g and 42h, at another end. During operation the coupling 40b of the collet 40 may engage the external groove 42e of the sliding sleeve 42 and thereby displace the sliding sleeve in the longitudinal direction. Since the coupling 40b of the collet 40 is resilient, the collet 40 may be disengaged or reengaged with the sliding sleeve 42. An annular valve member 44 defining an internal passage 44a, having a first throat 44aa and a second throat 44ab, includes a flange 44b at one end, having external splines 44c for engaging the internal splines 14f of the second tubular support member 14, a first set of radial passages, 44da and 44db, a second set of radial passages, 44ea and 44eb, and a threaded portion 44f at another end. The sliding sleeve 42 and the valve member 44 define an annular bypass passage 46 that, depending upon the position of the sliding sleeve 42, permits fluidic materials to flow from the passage 44 through the first radial passages, 44da and 44db, the bypass passage 46, and the second radial passages, 44ea and 44eb, back into the passage 44. In this manner, fluidic materials may bypass the portion of the passage 44 between the first and second radial passages, 44ea, 44eb, 44da, and 44db. Furthermore, the sliding sleeve 42 and the

valve member 44 together define a sliding sleeve valve for controllably permitting fluidic materials to bypass the intermediate portion of the passage 44a between the first and second passages, 44da, 44db, 44ea, and 44eb. During operation, the flange 44b limits movement of the sliding sleeve 42 in the longitudinal direction.

The collet 40 includes a set of couplings 40b such as, for example, fingers, that engage the external groove 42e of the sliding sleeve 42. During operation, the collet couplings 40b latch over and onto the external groove 42e of the sliding sleeve 42. A longitudinal force of at least about 4.448 to 57.827 kN (10,000 to 13,000 lbf) is required to pull the couplings 40b off of, and out of engagement with, the external groove 42e of the sliding sleeve 42. The application of a longitudinal force less than about 4.448 to 57.827 kN (10,000 to 13,000 lbf) indicates that the collet couplings 40b are latched onto the external shoulder of the sliding sleeve 42, and that the sliding sleeve 42 is in the up or the down position relative to the valve member 44. The collet 40 includes a conventional internal shoulder that transfers the weight of the first tubular support member 12 and expansion cone 18 onto the sliding sleeve 42. The collet 40 further includes a conventional set of internal lugs for engaging the splines 44c of the valve member 44.

An annular valve seat 48 defining a conical internal passage 48a for receiving a conventional float valve element 50 includes an annular recess 48b, having an internally threaded portion 48c for engaging the threaded portion 44f of the valve member 44, at one end, and an externally threaded portion 48d at another end. Alternatively, the float valve element 50 is omitted. An annular valve seat mounting element 52 defining an internal passage 52a for receiving the valve seat 48 and float valve 50 includes an internally threaded portion 52b for engaging the externally threaded portion 48d of the valve seat 48, an externally threaded portion 52c, an internal flange 52d, radial passages, 52ea and 52eb, and an end member 52f, having axial passages, 52fa and 52fb.

A shoe 54 defining an internal passage 54a for receiving the valve seat mounting element 52 includes a first annular recess 54b, having an externally threaded portion 54c, and a second annular recess 54d, having an externally threaded

portion 54e for engaging the threaded portion 20d of the expansion cone launcher 20, at one end, a first threaded counterbore 54f for engaging the threaded portion 52c of the of the mounting element, and a second counterbore 54g for mating with the end member 52f of the mounting element. The shoe 54 is fabricated from a ceramic and/or a composite material in order to facilitate the subsequent removal of the shoe by drilling. A seventh tubular support member 56 defining an internal passage 56a for receiving the sliding sleeve 42 and the valve member 44 is positioned within the expansion cone launcher 20 that includes an internally threaded portion 56b at one end for engaging the externally threaded portion 54c of the annular recess 54b of the shoe 54. During operation of the assembly, the end of the seventh tubular support member 56 limits the longitudinal movement of the expansion cone 18 in the direction of the shoe 54 by limiting the longitudinal movement of the sixth tubular support member 38. An annular centralizer 58 defining an internal passage 58a for movably supporting the sliding sleeve 42 is positioned within the seventh tubular support member 56 that includes axial passages 58b and 58c. The centralizer 58 maintains the sliding sleeve 42 and valve member 44 is a central position within the assembly 10.

Referring to Figs. 2a-2b, during operation, the assembly 10 may be used to form or repair a wellbore casing by implementing a method 200 in which, as illustrated in Figs. 3a-3c, the assembly 10 may initially be positioned within a wellbore 100 having a preexisting wellbore casing 102 by coupling a conventional tubular member 104 defining an internal passage 104a to the threaded portion 12b of the first tubular support member 12 in step 202. During placement of the assembly 10 within the wellbore 100, fluidic materials 106 within the wellbore 100 below the assembly 10 are conveyed through the assembly 10 and into the passage 104a by the fluid passages 52fa, 52fb, 54a, 48a, 44a, and 14a. In this manner, surge pressures that can be created during placement of the assembly 10 within the wellbore 100 are minimized. The float valve element 50 is pre-set in an auto-fill configuration to permit the fluidic materials 106 to pass through the conical passage 48a of the valve seat 48.

Referring to Figs. 4a-4c, in step 204, fluidic materials 108 may then be injected into and through the tubular member 104 and assembly 10 to thereby ensure that all of the fluid passages 104a, 14a, 44a, 48a, 54a, 52fa, and 52fb are functioning properly.

Referring to Figs. 5a-5c, in step 206, a bottom plug 110 may then be injected into the fluidic materials 108 and into the assembly 10 and then positioned in the throat passage 44ab of the valve member 44. In this manner, the region of the passage 44a upstream from the plug 110 may be fluidicly isolated from the region of the passage 44a downstream from the plug 110. The proper placement of the plug 110 may be indicated by a corresponding increase in the operating pressure of the fluidic material 108.

Referring to Figs. 6a-6c, in step 208, the sliding sleeve 42 may then be displaced relative to the valve member 44 by displacing the tubular member 104 by applying, for example, a downward force of approximately 5,000 lbf on the assembly 10. In this manner, the tubular member 104, the first tubular support member 12, the second tubular support member 14, the third tubular support member 16, the expansion cone 18, the annular spacer 22, the fourth tubular support member 24, the fifth tubular support member 26, the sixth tubular support member 38, the collet 40, and the sliding sleeve 42 are displaced in the longitudinal direction relative to the expansion cone launcher 20 and the valve member 44. In this manner, fluidic materials within the passage 44a upstream of the plug 110 may bypass the plug by passing through the first passages, 44da and 44db, through the annular passage 46, and through the second passages, 44ea and 44eb, into the region of the passage 44a downstream from the plug. Furthermore, in this manner, the rupture disc 36 is fluidicly isolated from the passages 14a and 44a.

Referring to Figs. 7a-7c, in step 210, a hardenable fluidic sealing material 112 may then be injected into the assembly 10 and conveyed through the passages 104a, 14a, 44a, 44da, 44db, 46, 44ea, 44eb, 48a, 54a, 52fa, and 52fb into the wellbore 100. In this manner, a hardenable fluidic sealing material such as, for example, cement, may be injected into the annular region between the expansion

cone launcher 20 and the wellbore 100 in order to subsequently form an annular body of cement around the radially expanded expansion cone launcher 20. Furthermore, in this manner, the radial passage 30a and the rupture disc 36 are not exposed to the hardenable fluidic sealing material 112.

Referring to Figs. 8a-8c, in step 212, upon the completion of the injection of the hardenable fluidic sealing material 112, a nonhardenable fluidic material 114 may be injected into the assembly 10, and a top plug 116 may then be injected into the assembly 10 along with the fluidic materials 114 and then positioned in the throat passage 44aa of the valve member 44. In this manner, the region of the passage 44a upstream from the first passages, 44da and 44db, may be fluidicly isolated from the first passages. The proper placement of the plug 116 may be indicated by a corresponding increase in the operating pressure of the fluidic material 114.

Referring to Fig. 9a-9c, in step 214, the sliding sleeve 42 may then be displaced relative to the valve member 44 by displacing the tubular member 104 by applying, for example, an upward force of approximately 57.827 kN (13,000 lbf) on the assembly 10. In this manner, the tubular member 104, the first tubular support member 12, the second tubular support member 14, the third tubular support member 16, the expansion cone 18, the annular spacer 22, the fourth tubular support member 24, the fifth tubular support member 26, the sixth tubular support member 38, the collet 40, and the sliding sleeve 42 are displaced in the longitudinal direction relative to the expansion cone launcher 20 and the valve member 44. In this manner, fluidic materials within the passage 44a upstream of the plug 110 may no longer bypass the plug by passing through the first passages, 44da and 44db, through the annular passage 46, and through the second passages, 44ea and 44eb, into the region of the passage 44a downstream from the plug. Furthermore, in this manner, the rupture disc 36 is no longer fluidicly isolated from the fluid passages 14a and 44a.

Referring to Figs. 10a-10c, in step 216, the fluidic material 114 may be injected into the assembly 10. The continued injection of the fluidic material 114

may increase the operating pressure within the passages 14a and 44a until the burst disc 36 is opened thereby permitting the pressurized fluidic material 114 to pass through the radial passage 30a and into an annular region 118 defined by the second tubular support member 14, the third tubular support member 16, the sixth tubular support member 38, the collet 40, the sliding sleeve 42, the shoe 54, and the seventh tubular support member 56. The pressurized fluidic material 114 within the annular region 118 directly applies a longitudinal force upon the fifth tubular support member 26 and the sixth tubular support member 38. The longitudinal force in turn is applied to the expansion cone 18. In this manner, the expansion cone 18 is displaced relative to the expansion cone launcher 20 thereby radially expanding and plastically deforming the expansion cone launcher.

Alternatively in the method 200, the injection and placement of the top plug 116 into the liner hanger assembly 10 in step 212 may be omitted.

Alternatively, in the method 200, in step 202, the assembly 10 is positioned at the bottom of the wellbore 100.

As illustrated in Figs. 11a-11b, during operation, the assembly 10 may be used to form or repair a wellbore casing by implementing a method 250 in which, as illustrated in Figs. 3a-3c, the assembly 10 may initially be positioned within a wellbore 100 having a preexisting wellbore casing 102 by coupling a conventional tubular member 104 defining an internal passage 104a to the threaded portion 12b of the first tubular support member 12 in step 252. During placement of the assembly 10 within the wellbore 100, fluidic materials 106 within the wellbore 100 below the assembly 10 are conveyed through the assembly 10 and into the passage 104a by the fluid passages 52fa, 52fb, 54a, 48a, 44a, and 14a. In this manner, surge pressures that can be created during placement of the assembly 10 within the wellbore 100 are minimized. The float valve element 50 is pre-set in an auto-fill configuration to permit the fluidic materials 106 to pass through the conical passage 48a of the valve seat 48.

Referring to Figs. 4a-4c, in step 254, fluidic materials 108 may then be injected into and through the tubular member 104 and assembly 10 to thereby ensure

that all of the fluid passages 104a, 14a, 44a, 48a, 54a, 52fa, and 52fb are functioning properly.

Referring to Figs. 5a-5c, in step 256, the bottom plug 110 may then be injected into the fluidic materials 108 and into the assembly 10 and then positioned in the throat passage 44ab of the valve member 44. In this manner, the region of the passage 44a upstream from the plug 110 may be fluidicly isolated from the region of the passage 44a downstream from the plug 110. The proper placement of the plug 110 may be indicated by a corresponding increase in the operating pressure of the fluidic material 108.

Referring to Figs. 12a-12c, in step 258, a fluidic material 114 may then be injected into the assembly to thereby increase the operating pressure within the passages 14a and 44a until the burst disc 36 is opened thereby permitting the pressurized fluidic material 114 to pass through the radial passage 30a and into an annular region 118 defined by the second tubular support member 14, the third tubular support member 16, the sixth tubular support member 38, the collet 40, the sliding sleeve 42, the shoe 54, and the seventh tubular support member 56. The pressurized fluidic material 114 within the annular region 118 directly applies a longitudinal force upon the fifth tubular support member 26 and the sixth tubular support member 38. The longitudinal force in turn is applied to the expansion cone 18. In this manner, the expansion cone 18 is displaced relative to the expansion cone launcher 20 thereby disengaging the collet 40 and the sliding sleeve 42 and radially expanding and plastically deforming the expansion cone launcher. The radial expansion process in step 408 is continued to a location below the overlap between the expansion cone launcher 20 and the preexisting wellbore casing 102.

Referring to Figs. 13a-13c, in step 260, the sliding sleeve 42 may then be displaced relative to the valve member 44 by (1) displacing the expansion cone 18 in a downward direction using the tubular member 104 and (2) applying, using the tubular member 104 a downward force of, for example, approximately 2.224 kN (5,000 lbf) on the assembly 10. In this manner, the coupling 40b of the collet 40 reengages the external groove 42e of the sliding sleeve 42. Furthermore, in this

manner, the tubular member 104, the first tubular support member 12, the second tubular support member 14, the third tubular support member 16, the expansion cone 18, the annular spacer 22, the fourth tubular support member 24, the fifth tubular support member 26, the sixth tubular support member 38, the collet 40, and the sliding sleeve 42 are displaced in the longitudinal direction relative to the expansion cone launcher 20 and the valve member 44. In this manner, fluidic materials within the passage 44a upstream of the plug 110 may bypass the plug by passing through the first passages, 44da and 44db, through the annular passage 46, and through the second passages, 44ea and 44eb, into the region of the passage 44a downstream from the plug. Furthermore, in this manner, the fluid passage 30a is fluidicly isolated from the passages 14a and 44a.

Referring to Figs. 14a-14c, in step 262, the hardenable fluidic sealing material 112 may then be injected into the assembly 10 and conveyed through the passages 104a, 14a, 44a, 44da, 44db, 46, 44ea, 44eb, 48a, 54a, 52fa, and 52fb into the wellbore 100. In this manner, a hardenable fluidic sealing material such as, for example, cement, may be injected into the annular region between the expansion cone launcher 20 and the wellbore 100 in order to subsequently form an annular body of cement around the radially expanded expansion cone launcher 20. Furthermore, in this manner, the radial passage 30a and the rupture disc 36 are not exposed to the hardenable fluidic sealing material 112.

Referring to Figs. 15a-15c, in step 264, upon the completion of the injection of the hardenable fluidic sealing material 112, the nonhardenable fluidic material 114 may be injected into the assembly 10, and the top plug 116 may then be injected into the assembly 10 along with the fluidic materials 114 and then positioned in the throat passage 44aa of the valve member 44. In this manner, the region of the passage 44a upstream from the first passages, 44da and 44db, may be fluidicly isolated from the first passages. The proper placement of the plug 116 may be indicated by a corresponding increase in the operating pressure of the fluidic material 114.

Referring to Figs. 16a-16c, in step 266, the sliding sleeve 42 may then be displaced relative to the valve member 44 by displacing the tubular member 104 by applying, for example, an upward force of approximately 57.827 kN (13,000 lbf) on the assembly 10. In this manner, the tubular member 104, the first tubular support member 12, the second tubular support member 14, the third tubular support member 16, the expansion cone 18, the annular spacer 22, the fourth tubular support member 24, the fifth tubular support member 26, the sixth tubular support member 38, the collet 40, and the sliding sleeve 42 are displaced in the longitudinal direction relative to the expansion cone launcher 20 and the valve member 44. In this manner, fluidic materials within the passage 44a upstream of the plug 110 may no longer bypass the plug by passing through the first passages, 44da and 44db, through the annular passage 46, and through the second passages, 44ea and 44eb, into the region of the passage 44a downstream from the plug. Furthermore, in this manner, the passage 30a is no longer fluidicly isolated from the fluid passages 14a and 44a.

Referring to Figs. 17a-17c, in step 268, the fluidic material 114 may be injected into the assembly 10. The continued injection of the fluidic material 114 may increase the operating pressure within the passages 14a, 30a, and 44a and the annular region 118. The pressurized fluidic material 114 within the annular region 118 directly applies a longitudinal force upon the fifth tubular support member 26 and the sixth tubular support member 38. The longitudinal force in turn is applied to the expansion cone 18. In this manner, the expansion cone 18 is displaced relative to the expansion cone launcher 20 thereby completing the radial expansion of the expansion cone launcher.

Alternatively, in the method 250, the injection and placement of the top plug 116 into the liner hanger assembly 10 in step 264 may omitted.

Alternatively, in the method 250, in step 252, the assembly 10 is positioned at the bottom of the wellbore 100.

Alternatively, in the method 250: (1) in step 252, the assembly 10 is positioned proximate a position below a preexisting section of the wellbore casing 102, and (2) in step 258, the expansion cone launcher 20, and any expandable

tubulars coupled to the threaded portion 20c of the expansion cone launcher, are radially expanded and plastically deformed until the shoe 54 of the assembly 10 is proximate the bottom of the wellbore 100. In this manner, the radial expansion process using the assembly 10 provides a telescoping of the radially expanded tubulars into the wellbore 100.

The assembly 10 may be operated to form a wellbore casing by including or excluding the float valve 50.

The float valve 50 may be operated in an auto-fill configuration in which tabs are positioned between the float valve 50 and the valve seat 48. In this manner, fluidic materials within the wellbore 100 may flow into the assembly 10 from below thereby decreasing surge pressures during placement of the assembly 10 within the wellbore 100. Furthermore, pumping fluidic materials through the assembly 10 at rate of about 1.2 to $2m^3$/min (6 to 8 bbl/min) will displace the tabs from the valve seat 48 and thereby allow the float valve 50 to close.

Prior to the placement of any of the plugs, 110 and 116, into the assembly 10, fluidic materials can be circulated through the assembly 10 and into the wellbore 100.

Once the bottom plug 110 has been positioned into the assembly 10, fluidic materials can only be circulated through the assembly 10 and into the wellbore 100 if the sliding sleeve 42 is in the down position.

Once the sliding sleeve 42 is positioned in the down position, the passage 30a and rupture disc 36 are fluidicly isolated from pressurized fluids within the assembly 10.

Once the top plug 116 has been positioned into the assembly 10, no fluidic materials can be circulated through the assembly 10 and into the wellbore 100.

The assembly 10 may be operated to form or repair a wellbore casing, a pipeline, or a structural support.

Referring to Figs. 18, 18a, 18b, and 18c, a liner hanger assembly 300 includes a first tubular support member 312 defining an internal passage 312a that includes a threaded counterbore 312b at one end, and a threaded counterbore 312c at

another end. A second tubular support member 314 defining an internal passage 314a includes a first threaded portion 314b at a first end that is coupled to the threaded counterbore 312c of the first tubular support member 312, a stepped flange 314c, a counterbore 314d, a threaded portion 314e, and internal splines 314f at another end. The stepped flange 314c of the second tubular support member 314 further defines radial passages 314g, 314h, 314i, and 314j.

A third tubular support member 316 defining an internal passage 316a for receiving the second tubular support member 314 includes a first flange 316b, a second flange 316c, a first counterbore 316d, a second counterbore 316e having an internally threaded portion 316f, and an internal flange 316g. The second flange 316c further includes radial passages 316h and 316i.

An annular expansion cone 318 defining an internal passage 318a for receiving the second and third tubular support members, 314 and 316, includes a counterbore 318b at one end, and a counterbore 318c at another end for receiving the flange 316b of the second tubular support member 316. The annular expansion cone 318 further includes an end face 318d that mates with an end face 316j of the flange 316c of the second tubular support member 316, and an exterior surface 318e having a conical shape in order to facilitate the radial expansion of tubular members. A tubular expansion cone launcher 320 is movably coupled to the exterior surface 318e of the expansion cone 318 and includes a first portion 320a having a first wall thickness, a second portion 320b having a second wall thickness, a threaded portion 320c at one end, and a threaded portion 320d at another end. The second portion 320b of the expansion cone launcher 320 mates with the conical outer surface 318e of the expansion cone 318. The second wall thickness of the second portion 320b is less than the first wall thickness of the first portion 320a in order to optimize the radial expansion of the expansion cone launcher 320 by the relative axial displacement of the expansion cone 318. One or more expandable tubulars are coupled to the threaded connection 320c of the expansion cone launcher 320. In this manner, the assembly 300 may be used to radially expand and plastically deform, for example, thousands of feet of expandable tubulars.

An annular spacer 322 defining an internal passage 322a for receiving the second tubular support member 314 is received within the counterbore 318b of the expansion cone 318, and is positioned between an end face 312d of the first tubular support member 312 and an end face of the counterbore 318b of the expansion cone 318. A fourth tubular support member 324 defining an internal passage 324a for receiving the second tubular support member 314 includes a flange 324b that is received within the counterbore 316d of the third tubular support member 316. A fifth tubular support member 326 defining an internal passage 326a for receiving the second tubular support member 314 includes an internal flange 326b for mating with the flange 314c of the second tubular support member and a flange 326c for mating with the internal flange 316g of the third tubular support member 316.

An annular sealing member 328, an annular sealing and support member 330, an annular sealing member 332, and an annular sealing and support member 334 are received within the counterbore 314d of the second tubular support member 314. The annular sealing and support member 330 further includes a radial opening 330a for supporting a rupture disc 336 within the radial opening 314g of the second tubular support member 314 and a sealing member 330b for sealing the radial opening 314h of the second tubular support member. The annular sealing and support member 334 further includes sealing members 334a and 334b for sealing the radial openings 314i and 314j, respectively, of the second tubular support member 314. The rupture disc 336 opens when the operating pressure within the radial opening 330b is about 6,894.745 to 34,473.724 KPa (1000 to 5000 psi). In this manner, the rupture disc 336 provides a pressure sensitive valve for controlling the flow of fluidic materials through the radial opening 330a. Alternatively, the assembly 300 includes a plurality of radial passages 330a, each with corresponding rupture discs 336.

A sixth tubular support member 338 defining an internal passage 338a for receiving the second tubular support member 314 includes a threaded portion 338b at one end that is coupled to the threaded portion 316f of the third tubular support member 316 and a flange 338c at another end that is movably coupled to the interior

of the expansion cone launcher 320. An annular collet 340 includes a threaded portion 340a that is coupled to the threaded portion 314e of the second tubular support member 314, and a resilient coupling 340b at another end.

An annular sliding sleeve 342 defining an internal passage 342a includes an internal flange 342b, having sealing members 342c and 342d, and an external groove 342e for releasably engaging the coupling 340b of the collet 340 at one end, and an internal flange 342f, having sealing members 342g and 342h, at another end. During operation, the coupling 340b of the collet 340 may engage the external groove 342e of the sliding sleeve 342 and thereby displace the sliding sleeve in the longitudinal direction. Since the coupling 340b of the collet 340 is resilient, the collet 340 may be disengaged or reengaged with the sliding sleeve 342. An annular valve member 344 defining an internal passage 344a, having a throat 344aa, includes a flange 344b at one end, having external splines 344c for engaging the internal splines 314f of the second tubular support member 314, an interior flange 344d having a first set of radial passages, 344da and 344db, and a counterbore 344e, a second set of radial passages, 344fa and 344fb, and a threaded portion 344g at another end.

An annular valve member 346 defining an internal passage 346a, having a throat 346aa, includes an end portion 346b that is received in the counterbore 344e of the annular valve member 344, a set of radial openings, 346ca and 346cb, and a flange 346d at another end. An annular valve member 348 defining an internal passage 348a for receiving the annular valve members 344 and 346 includes a flange 348b having a threaded counterbore 348c at one end for engaging the threaded portion 344g of the annular valve member, a counterbore 348d for mating with the flange 346d of the annular valve member, and a threaded annular recess 348e at another end.

The annular valve members 344, 346, and 348 define an annular passage 350 that fluidicly couples the radial passages 344fa, 344fb, 346ca, and 346cb. Furthermore, depending upon the position of the sliding sleeve 342, the fluid passages, 344da and 344db, may be fluidicly coupled to the passages 344fa, 344fb,

346ca, 346cb, and 350. In this manner, fluidic materials may bypass the portion of the passage 346a between the passages 344da, 344db, 346ca, and 346cb.

Furthermore, the sliding sleeve 342 and the valve members 344, 346, and 348 together define a sliding sleeve valve for controllably permitting fluidic materials to bypass the intermediate portion of the passage 346a between the passages, 344da, 344db, 346ca, and 346cb. During operation of the sliding sleeve valve, the flange 348b limits movement of the sliding sleeve 342 in the longitudinal direction.

The collet 340 includes a set of couplings 340b that engage the external groove 342e of the sliding sleeve 342. During operation, the collet couplings 340b latch over and onto the external groove 342e of the sliding sleeve 342. A longitudinal force of at least about 4.448 to 57.827 kN (10,000 to 13,000 lbf) is required to pull the couplings 340b off of, and out of engagement with, the external groove 342e of the sliding sleeve 342. The application of a longitudinal force less than about 4.448 to 57.827 kN (10,000 to 13,000 lbf) indicates that the collet couplings 340b are latched onto the external shoulder of the sliding sleeve 342, and that the sliding sleeve 342 is in the up or the down position relative to the valve member 344. The collet 340 includes a conventional internal shoulder that transfers the weight of the first tubular support member 312 and expansion cone 318 onto the sliding sleeve 342. The collet 340 further includes a conventional set of internal lugs for engaging the splines 344c of the valve member 344.

An annular valve seat 352 defining a conical internal passage 352a for receiving a conventional float valve element 354 includes a threaded annular recess 352b for engaging the threaded portion 348e of the valve member 348, at one end, and an externally threaded portion 352c at another end. Alternatively, the float valve element 354 is omitted. An annular valve seat mounting element 356 defining an internal passage 356a for receiving the valve seat 352 and float valve 354 includes an internally threaded portion 356b for engaging the externally threaded portion 352c of the valve seat 352, an externally threaded portion 356c, an internal flange 356d, radial passages, 356ea and 356eb, and an end member 356f, having axial passages, 356fa and 356fb.

A shoe 358 defining an internal passage 358a for receiving the valve seat mounting element 356 includes a first threaded annular recess 358b, and a second threaded annular recess 358c for engaging the threaded portion 320d of the expansion cone launcher 320, at one end, a first threaded counterbore 358d for engaging the threaded portion 356c of the of the valve seat mounting element, and a second counterbore 358e for mating with the end member 356f of the mounting element. The shoe 358 is fabricated from a ceramic and/or a composite material in order to facilitate the subsequent removal of the shoe by drilling.

A seventh tubular support member 360 defining an internal passage 360a for receiving the sliding sleeve 342 and the valve members 344, 346, and 348 is positioned within the expansion cone launcher 320 that includes an internally threaded portion 360b at one end for engaging the externally threaded portion of the annular recess 358b of the shoe 358. During operation of the assembly, the end of the seventh tubular support member 360 limits the longitudinal movement of the expansion cone 318 in the direction of the shoe 358 by limiting the longitudinal movement of the sixth tubular support member 338. An annular centralizer 362 defining an internal passage 362 for supporting the valve member 348 is positioned within the seventh tubular support member 360 that includes axial passages 362b and 362c.

Referring to Figs. 19a-19b, during operation, the assembly 300 may be used to form or repair a wellbore casing by implementing a method 400 in which, as illustrated in Figs. 20a-20c, the assembly 300 may initially be positioned within a wellbore 1000 having a preexisting wellbore casing 1002 by coupling a conventional tubular member 1004 defining an internal passage 1004a to the threaded portion 312b of the first tubular support member 312 in step 402. During placement of the assembly 300 within the wellbore 1000, fluidic materials 1006 within the wellbore 1000 below the assembly 300 are conveyed through the assembly 300 and into the passage 1004a by the fluid passages 356fa, 356fb, 352a, 348a, 346a, 344a, and 314a. In this manner, surge pressures that can be created during placement of the assembly 300 within the wellbore 1000 are minimized. The

float valve element 354 is pre-set in an auto-fill configuration to permit the fluidic materials 1006 to pass through the conical passage 352a of the valve seat 352.

Referring to Figs. 21a-21c, in step 404, fluidic materials 1008 may then be injected into and through the tubular member 1004 and assembly 300 to thereby ensure that all of the fluid passages 1004a, 314a, 344a, 346a, 348a, 352a, 356fa, and 356fb are functioning properly.

Referring to Figs. 22a-22c, in step 406, a bottom plug 1010 may then be injected into the fluidic materials 1008 and into the assembly 300 and then positioned in the throat passage 346aa of the valve member 346. In this manner, the region of the passage 346a upstream from the plug 1010 may be fluidicly isolated from the region of the passage 346a downstream from the plug 1010. The proper placement of the plug 1010 may be indicated by a corresponding increase in the operating pressure of the fluidic material 1008.

Referring to Figs. 23a-23c, in step 408, the sliding sleeve 342 may then be displaced relative to the valve member 344 by displacing the tubular member 1004 by applying, for example, a downward force of approximately 2.224 kN (5,000 lbf) on the assembly 300. In this manner, the tubular member 1004, the first tubular support member 312, the second tubular support member 314, the third tubular support member 316, the expansion cone 318, the annular spacer 322, the fourth tubular support member 324, the fifth tubular support member 326, the sixth tubular support member 338, the collet 340, and the sliding sleeve 342 are displaced in the longitudinal direction relative to the expansion cone launcher 320 and the valve member 344. In this manner, fluidic materials within the passage 344a upstream of the plug 1010 may bypass the plug by passing through the first passages, 344da and 344db, through the annular passage 342a, through the second passages, 344fa and 344fb, through the annular passage 350, through the passages, 346ca and 346cb, into the region of the passage 348a downstream from the plug. Furthermore, in this manner, the rupture disc 336 is fluidicly isolated from the passages 314a and 344a.

Referring to Figs. 24a-24c, in step 410, a hardenable fluidic sealing material 1012 may then be injected into the assembly 300 and conveyed through the passages

1004a, 314a, 344a, 344da, 344db, 342a, 344fa, 344fb, 350, 346ca, 346cb, 348a, 352a, 356fa, and 356fb into the wellbore 1000. In this manner, a hardenable fluidic sealing material such as, for example, cement, may be injected into the annular region between the expansion cone launcher 320 and the wellbore 1000 in order to subsequently form an annular body of cement around the radially expanded expansion cone launcher 320. Furthermore, in this manner, the radial passage 330a and the rupture disc 336 are not exposed to the hardenable fluidic sealing material 1012.

Referring to Figs. 25a-25c, in step 412, upon the completion of the injection of the hardenable fluidic sealing material 1012, a nonhardenable fluidic material 1014 may be injected into the assembly 300, and a top plug 1016 may then be injected into the assembly 300 along with the fluidic materials 1014 and then positioned in the throat passage 344aa of the valve member 344. In this manner, the region of the passage 344a upstream from the top plug 1016 may be fluidicly isolated from region downstream from the top plug. The proper placement of the plug 1016 may be indicated by a corresponding increase in the operating pressure of the fluidic material 1014.

Referring to Fig. 26a-26c, in step 414, the sliding sleeve 42 may then be displaced relative to the valve member 344 by displacing the tubular member 1004 by applying, for example, an upward force of approximately 57.827 kN (13,000 lbf) on the assembly 300. In this manner, the tubular member 1004, the first tubular support member 312, the second tubular support member 314, the third tubular support member 316, the expansion cone 318, the annular spacer 322, the fourth tubular support member 324, the fifth tubular support member 326, the sixth tubular support member 338, the collet 340, and the sliding sleeve 342 are displaced in the longitudinal direction relative to the expansion cone launcher 320 and the valve member 344. In this manner, fluidic materials within the passage 344a upstream of the bottom plug 1010 may no longer bypass the bottom plug by passing through the first passages, 344da and 344db, through the annular passage 342a, through the second passages, 344fa and 344fb, through the annular passage 350, and through the

passages, 346ca and 346cb, into region of the passage 348a downstream from the bottom plug. Furthermore, in this manner, the rupture disc 336 is no longer fluidicly isolated from the fluid passages 314a and 344a.

Referring to Figs. 27a-27c, in step 416, the fluidic material 1014 may be injected into the assembly 300. The continued injection of the fluidic material 1014 may increase the operating pressure within the passages 314a and 344a until the burst disc 336 is opened thereby permitting the pressurized fluidic material 1014 to pass through the radial passage 330a and into an annular region 1018 defined by the second tubular support member 314, the third tubular support member 316, the sixth tubular support member 338, the collet 340, the sliding sleeve 342, the valve members, 344 and 348, the shoe 358, and the seventh tubular support member 360. The pressurized fluidic material 1014 within the annular region 1018 directly applies a longitudinal force upon the fifth tubular support member 326 and the sixth tubular support member 338. The longitudinal force in turn is applied to the expansion cone 318. In this manner, the expansion cone 318 is displaced relative to the expansion cone launcher 320 thereby radially expanding and plastically deforming the expansion cone launcher.

Alternatively, in the method 400, the injection and placement of the top plug 1016 into the liner hanger assembly 300 in step 412 may omitted.

Alternatively, in the method 400, in step 402, the assembly 300 is positioned at the bottom of the wellbore 1000.

As illustrated in Figs. 28a-28b, during operation, the assembly 300 may be used to form or repair a wellbore casing by implementing a method 450 in which, as illustrated in Figs. 20a-20c, the assembly 300 may initially be positioned within a wellbore 1000 having a preexisting wellbore casing 1002 by coupling a conventional tubular member 1004 defining an internal passage 1004a to the threaded portion 312b of the first tubular support member 312 in step 452. During placement of the assembly 300 within the wellbore 1000, fluidic materials 1006 within the wellbore 1000 below the assembly 300 are conveyed through the assembly 300 and into the passage 1004a by the fluid passages 356fa, 356fb, 352a,

348a, 346a, 344a, and 314a. In this manner, surge pressures that can be created during placement of the assembly 300 within the wellbore 1000 are minimized. The float valve element 354 is pre-set in an auto-fill configuration to permit the fluidic materials 1006 to pass through the conical passage 352a of the valve seat 352.

Referring to Figs. 21a-21c, in step 454, in step 454, fluidic materials 1008 may then be injected into and through the tubular member 1004 and assembly 300 to thereby ensure that all of the fluid passages 1004a, 314a, 344a, 346a, 348a, 352a, 356fa, and 356fb are functioning properly.

Referring to Figs. 22a-22c, in step 456, the bottom plug 1010 may then be injected into the fluidic materials 1008 and into the assembly 300 and then positioned in the throat passage 346aa of the valve member 346. In this manner, the region of the passage 346a upstream from the plug 1010 may be fluidicly isolated from the region of the passage 346a downstream from the plug 1010. The proper placement of the plug 1010 may be indicated by a corresponding increase in the operating pressure of the fluidic material 1008.

Referring to Figs. 29a-29c, in step 458, the fluidic material 1014 may then be injected into the assembly 300 to thereby increase the operating pressure within the passages 314a and 344a until the burst disc 336 is opened thereby permitting the pressurized fluidic material 1014 to pass through the radial passage 330a and into an annular region 1018 defined by the defined by the second tubular support member 314, the third tubular support member 316, the sixth tubular support member 338, the collet 340, the sliding sleeve 342, the valve members, 344 and 348, the shoe 358, and the seventh tubular support member 360. The pressurized fluidic material 1014 within the annular region 1018 directly applies a longitudinal force upon the fifth tubular support member 326 and the sixth tubular support member 338. The longitudinal force in turn is applied to the expansion cone 318. In this manner, the expansion cone 318 is displaced relative to the expansion cone launcher 320 thereby disengaging the collet 340 and the sliding sleeve 342 and radially expanding and plastically deforming the expansion cone launcher. The radial expansion process in

step 458 is continued to a location below the overlap between the expansion cone launcher 320 and the preexisting wellbore casing 1002.

Referring to Figs. 30a-30c, in step 460, the sliding sleeve 342 may then be displaced relative to the valve member 344 by (1) displacing the expansion cone 318 in a downward direction using the tubular member 1004 and (2) applying, using the tubular member 1004 a downward force of, for example, approximately 2.224 kN (5,000 lbf) on the assembly 300. In this manner, the coupling 340b of the collet 340 reengages the external groove 342e of the sliding sleeve 342. Furthermore, in this manner, the tubular member 1004, the first tubular support member 312, the second tubular support member 314, the third tubular support member 316, the expansion cone 318, the annular spacer 322, the fourth tubular support member 324, the fifth tubular support member 326, the sixth tubular support member 338, the collet 340, and the sliding sleeve 342 are displaced in the longitudinal direction relative to the expansion cone launcher 320 and the valve member 344. In this manner, fluidic materials within the passage 344a upstream of the bottom plug 1010 may bypass the plug by passing through the passages, 344da and 344db, the annular passage 342a, the passages, 344fa and 344fb, the annular passage 350, and the passages, 346ca and 346cb, into the passage 348a downstream from the plug. Furthermore, in this manner, the fluid passage 330a is fluidicly isolated from the passages 314a and 344a.

Referring to Figs. 31a-31c, in step 462, the hardenable fluidic sealing material 1012 may then be injected into the assembly 300 and conveyed through the passages 1004a, 314a, 344a, 344da, 344db, 342, 344fa, 344fb, 350, 346ca, 346cb, 348a, 352b, 356fa, and 356fb into the wellbore 1000. In this manner, a hardenable fluidic sealing material such as, for example, cement, may be injected into the annular region between the expansion cone launcher 320 and the wellbore 1000 in order to subsequently form an annular body of cement around the radially expanded expansion cone launcher 320. Furthermore, in this manner, the radial passage 330a and the rupture disc 336 are not exposed to the hardenable fluidic sealing material 1012.

Referring to Figs. 32a-32c, in step 464, upon the completion of the injection of the hardenable fluidic sealing material 1012, the nonhardenable fluidic material 1014 may be injected into the assembly 300, and the top plug 1016 may then be injected into the assembly 300 along with the fluidic materials 1014 and then positioned in the throat passage 344aa of the valve member 344. In this manner, the region of the passage 344a upstream from the top plug 1016 may be fluidicly isolated from the region within the passage downstream from the top plug. The proper placement of the plug 1016 may be indicated by a corresponding increase in the operating pressure of the fluidic material 1014.

Referring to Figs. 33a-33c, in step 466, the sliding sleeve 342 may then be displaced relative to the valve member 344 by displacing the tubular member 1004 by applying, for example, an upward force of approximately 57.827 kN (13,000 lbf) on the assembly 300. In this manner, the tubular member 1004, the first tubular support member 312, the second tubular support member 314, the third tubular support member 316, the expansion cone 318, the annular spacer 322, the fourth tubular support member 324, the fifth tubular support member 326, the sixth tubular support member 338, the collet 340, and the sliding sleeve 342 are displaced in the longitudinal direction relative to the expansion cone launcher 320 and the valve member 344. In this manner, fluidic materials within the passage 344a upstream of the bottom plug 110 may no longer bypass the plug by passing through the passages, 344da and 344db, the annular passage 342a, the passages, 344fa and 344fb, the annular passage 350, and the passages, 346ca and 346cb, into the passage 348a downstream from the plug. Furthermore, in this manner, the passage 330a is no longer fluidicly isolated from the fluid passages 314a and 344a.

Referring to Figs. 34a-34c, in step 468, the fluidic material 1014 may be injected into the assembly 300. The continued injection of the fluidic material 1014 may increase the operating pressure within the passages 314a, 330a, and 344a and the annular region 1018. The pressurized fluidic material 1014 within the annular region 1018 directly applies a longitudinal force upon the fifth tubular support member 326 and the sixth tubular support member 338. The longitudinal force in

turn is applied to the expansion cone 318. In this manner, the expansion cone 318 is displaced relative to the expansion cone launcher 320 thereby completing the radial expansion of the expansion cone launcher.

Alternatively, in the method 450, the injection and placement of the top plug 1016 into the liner hanger assembly 300 in step 464 may omitted.

Alternatively, in the method 450, in step 452, the assembly 300 is positioned at the bottom of the wellbore 1000.

Alternatively, in the method 450: (1) in step 452, the assembly 300 is positioned proximate a position below a preexisting section of the wellbore casing 1002, and (2) in step 458, the expansion cone launcher 320, and any expandable tubulars coupled to the threaded portion 320c of the expansion cone launcher, are radially expanded and plastically deformed until the shoe 358 of the assembly 300 is proximate the bottom of the wellbore 1000. In this manner, the radial expansion process using the assembly 300 provides a telescoping of the radially expanded tubulars into the wellbore 1000.

The assembly 300 may be operated to form a wellbore casing by including or excluding the float valve 354.

The float valve 354 may be operated in an auto-fill configuration in which tabs are positioned between the float valve 354 and the valve seat 352. In this manner, fluidic materials within the wellbore 1000 may flow into the assembly 300 from below thereby decreasing surge pressures during placement of the assembly 300 within the wellbore 1000. Furthermore, pumping fluidic materials through the assembly 300 at rate of about 1.2 to 2m^3/min (6 to 8 bbl/min) will displace the tabs from the valve seat 352 and thereby allow the float valve 354 to close.

Prior to the placement of any of the plugs, 1010 and 1016, into the assembly 300, fluidic materials can be circulated through the assembly 300 and into the wellbore 1000.

Once the bottom plug 1010 has been positioned into the assembly 300, fluidic materials can only be circulated through the assembly 300 and into the wellbore 1000 if the sliding sleeve 342 is in the down position.

Once the sliding sleeve 342 is positioned in the down position, the passage 330a and rupture disc 336 are fluidicly isolated from pressurized fluids within the assembly 300.

Once the top plug 1016 has been positioned into the assembly 300, no fluidic materials can be circulated through the assembly 300 and into the wellbore 1000.

The assembly 300 may be operated to form or repair a wellbore casing, a pipeline, or a structural support.

Although this detailed description has shown and described illustrative embodiments of the invention, this description contemplates a wide range of modifications, changes, and substitutions within the scope of the claims. In some instances, one may employ some features without a corresponding use of the other features and accordingly, it is appropriate that readers should construe the appended claims broadly .

CLAIMS

1. An apparatus for forming a wellbore casing within a borehole within a subterranean formation, comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each having one or more pressure sensitive valves fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having first and second throat passages, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve.

2. A method of operating an apparatus for forming a wellbore casing within a borehole within a subterranean formation, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages and having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the borehole;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand the expandable tubular member.

3. The method of claim 2, wherein positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the borehole.

4. The method of claim 2, further comprising: positioning a top plug in the top throat passage.

5. A method of operating an apparatus for forming a wellbore casing within a borehole within a subterranean formation, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the borehole;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

injecting a non-hardenable fluidic material through the first fluid passages and the first radial passages and pressure sensitive valves into the annular region to radially expand a portion of the expandable tubular member;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand another portion of the expandable tubular member.

6. The method of claim 5, wherein positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the borehole.

7. The method of claim 5, wherein positioning the apparatus within the borehole comprises:

positioning an end of the expandable tubular member adjacent to a preexisting section of wellbore casing within the borehole.

8. The method of claim 5, wherein injecting a non-hardenable fluidic material into the first fluid passage and one or more first radial passages and pressure sensitive valves to radially expand a portion of the expandable tubular member comprises:

injecting a non-hardenable fluidic material into the first fluid passage and the one or more first radial passages and pressure sensitive valves to radially expand the

expandable tubular member until an end portion of the tubular member is positioned proximate the bottom of the borehole.

9. The method of claim 5, further comprising:

positioning a top plug in the top throat passage.

10. An apparatus for coupling an expandable tubular member to a preexisting structure, comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having first and second throat passages, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve.

11. A method of operating an apparatus for coupling an expandable tubular member to a preexisting structure, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the preexisting structure;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand the expandable tubular member.

12. The method of claim 11, wherein positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the preexisting structure.

13. The method of claim 11, further comprising:

positioning a top plug in the top throat passage.

14. A method of operating an apparatus for coupling an expandable tubular member to a preexisting structure, the apparatus comprising:

a first annular support member defining a first fluid passage and one or more first radial passages, each of the one or more first radial passages having a pressure sensitive valve fluidicly coupled to the first fluid passage;

an annular expansion cone coupled to the first annular support member;

an expandable tubular member movably coupled to the expansion cone;

a second annular support member defining a second fluid passage coupled to the expandable tubular member;

an annular valve member defining a third fluid passage fluidicly coupled to the first and second fluid passages having a top and a bottom throat passage, defining second and third radial passages fluidicly coupled to the third fluid passage, coupled to the second annular support member, and movably coupled to the first annular support member; and

an annular sleeve releasably coupled to the first annular support member and movably coupled to the annular valve member for controllably fluidicly coupling the second and third radial passages; and

wherein an annular region is defined by the region between the tubular member and the first annular support member, the second annular support member, the annular valve member, and the annular sleeve;

the method comprising:

positioning the apparatus within the preexisting structure;

injecting fluidic materials into the first, second and third fluid passages;

positioning a bottom plug in the bottom throat passage;

injecting a non-hardenable fluidic material through the first fluid passages and the first radial passages and pressure sensitive valves into the annular region to radially expand a portion of the expandable tubular member;

displacing the annular sleeve to fluidicly couple the second and third radial passages;

injecting a hardenable fluidic sealing material through the first, second, and third fluid passages, and the second and third radial passages;

displacing the annular sleeve to fluidicly decouple the second and third radial passages; and

injecting a non-hardenable fluidic material through the first fluid passage and the one or more first radial passages and pressure sensitive valves into the annular region to radially expand another portion of the expandable tubular member.

15. The method of claim 14, wherein positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to the bottom of the preexisting structure.

16. The method of claim 14, wherein positioning the apparatus within the preexisting structure comprises:

positioning an end of the expandable tubular member adjacent to a preexisting section of a structural element within the preexisting structure.

17. The method of claim 14, wherein injecting a non-hardenable fluidic material into the first fluid passage and one or more first radial passages and pressure sensitive valves to radially expand a portion of the expandable tubular member comprises:

injecting a non-hardenable fluidic material into the first fluid passage and one or more first radial passages and pressure sensitive valves to radially expand the expandable tubular member until an end portion of the tubular member is positioned proximate the bottom of the preexisting structure.

18. The method of claim 14, further comprising positioning a top plug in the top throat passage.